EnergyTag

THE LANTAU GROUP

CHINA POWER SECTOR AND POLICY LANDSCAPE FOR ROUND-THE-CLOCK CLEAN POWER

DISCLAIMER

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EXECUTIVE SUMMARY

This report has two aims. First, it provides a practical primer on how China's power sector works today: how electricity is traded and settled, how renewables are integrated, how storage is developing, and how green attributes are issued and claimed. Second, it uses that market reality as the lens for assessing the prospects for more time-resolved clean electricity procurement in China, including round-the-clock (RTC) clean power claims and granular matching.

Several issues are now emerging in China's provincial spot markets that are inherently time-dependent, including curtailment risk, periods of very low or negative prices, and solar-driven intra-day ramps. At the same time, storage is growing rapidly but still faces constraints in capturing system value through market revenues. These conditions increase the relevance of approaches that strengthen temporal resolution in price signals, contracting structures, and clean-attribute evidence, including granular matching.

WHERE CHINA STANDS TODAY ON THE JOURNEY TOWARD RTC CLEAN POWER

China is already laying many of the foundations that enable RTC-style approaches, but progress is uneven across provinces and not yet packaged into standard buyer-facing products. Spot market reform continues to advance province by province. As of Q1 2026, seven provincial spot markets have entered formal operation, with many others still in trial. This shift is strengthening time-varying price and settlement signals, but wholesale outcomes remain shaped by administrative price constraints and the continued dominance of mid- and long-term contracting. On the attribute side, China's Green Electricity Certificate (GEC) system is the national backbone for renewable claims, with same-year matching now the stated baseline. Some provinces have established hourly green power trading and offer users hourly blockchain-based consumption certificates, but GECs still track monthly consumption and access to settlement-grade interval data for third-party verification remains inconsistent. Its importance is increasing, however, as spot markets and requirements for time-resolved claims – particularly in the context of trade-linked frameworks like CBAM – become more prominent.

WHAT THE QUANTITATIVE EVIDENCE SUGGESTS ABOUT THE OPPORTUNITY

The report's quantitative indicators point to a system where the value of electricity is increasingly time-dependent. Provinces with high solar penetration show pronounced intra-day volatility, including extended periods of very weak or negative daytime prices in spot settlement. China's operating storage fleet continues to expand, while policy is shifting from mandated co-location toward market-based integration, even as monetisation remains constrained by market design. On the demand side, CBAM-covered goods still represent a relatively small share of China's exports to the EU, but the direction of travel in some trade-linked regimes is toward more stringent, time-stamped evidence. In parallel, GEC issuance and trading have scaled quickly while certificate prices have compressed, reinforcing the limits of purely volumetric approaches for expressing the value of clean electricity in specific hours.

WHAT THIS IMPLIES ABOUT CHINA'S TRAJECTORY

China's power sector reforms are moving toward greater temporal resolution, first in dispatch and settlement, and more slowly in how clean attributes are defined and claimed. Early pilots show that hourly matching can be demonstrated by linking time-stamped meter data to existing certificate processes, but these pilots do not yet constitute a general market product for corporate buyers. To pave the way for an RTC-style approach, it is therefore important to start to standardise and codify the institutional interfaces, including data access, consistent linkage between metering and settlement records, a registry approach that can accommodate timestamps alongside the current GEC backbone, and contract structures that remain compatible with China's retail market design. Progress on these items is likely to emerge first in more advanced provinces and use cases before being standardised as market institutions mature.

This transition to granular energy tracking and RTC clean power management can help to realise the full system value of flexibility and storage, the importance of which will only become more prominent as renewable penetration rises.

WHAT THIS MEANS FOR KEY STAKEHOLDERS

Moving toward RTC-style clean power in China can begin with targeted pilots in selected provinces, combined with disciplined work on data access, claim rules, and contracting templates

- For policymakers and market institutions: set clear claim boundaries, prevent double counting across GEC and ETS accounting, and establish workable data governance and verification pathways.
- For grid companies, exchanges, and third-party verifiers: enable access to settlement-level interval data and maintain consistent audit trails that can support third-party checks.
- For retailers and developers: translate time-resolved concepts into contracts buyers can use, including clear treatment of deviations, curtailment adjustments, and any firming arrangements.

Section 6.4 sets out a phased roadmap that starts with definitions and governance, builds MRV and registry foundations, enables commercial contracting pathways, and scales through pilots toward standardisation.

EXECUTIVE SNAPSHOT

Table 1: State of Play in China's Power Market

Dimension	What Is in Place / Trending	Why It Matters for Time-Resolved / RTC Claims
Market maturity	Spot-market reform progressing province by province; seven provincial spot markets in formal operation; most volume still anchored in mid-/long-term contracting; price constraints remain.	Time-varying settlement signals are improving, but uneven buyer exposure and administrative constraints limit the ability to price and standardise time-shaped clean products.
Renewable integration challenges	Re-emerging curtailment in some regions; intra-day volatility and periods of weak/negative spot settlement prices in high-solar provinces.	These are inherently time-dependent issues; time-resolved tracking and contracting can better orient incentives for the hours when the system is over- or under-supplied.
GEC status	GECs are the national backbone for renewable claims; same-year matching is the baseline; certificates remain monthly instruments; access to settlement-grade interval data for third-party verification is inconsistent.	Monthly instruments support annual claims but do not yet support hourly matching. Furthermore, there are no GECs for storage today, unlike e.g. the Renewable Electricity Guarantee of Origin (REGO) in Australia. GECs with hourly-tracking function would be ideal in reflecting the value of storage in time-shifting clean power. A potential pathway is to incorporate time-stamped generation data, including storage attributes into the GEC framework. This would allow certificates to reflect when electricity is produced. In the meantime, pilots demonstrate layering timestamps onto existing certificates is feasible but not yet standardised.
Storage build-out	Operating storage fleet continues to grow rapidly; policy shifting from mandatory co-location toward market-based integration; monetisation constrained by market design and revenue-stacking limitations.	Storage value is time-dependent; time-resolved accounting/claims can help make the 'hard-to-supply' hours visible and support differentiated firmed products, subject to market-rule constraints.

Table 2: How RTC-Oriented Procurement Helps Address Challenges

Observed / Emerging Issue	What Greater Temporal Resolution Changes	Expected Benefit (And Dependency, if Any)
Midday oversupply and negative/very low prices in some spot markets	Makes the time profile of supply and consumption explicit in procurement and claims, not just annual totals	Supports load shifting and 'firming' products that target scarce hours
Duck-curve ramps and increased balancing actions	Connects clean procurement signals to operationally relevant hours (ramp, reserve, congestion periods)	Improves alignment of incentives with system needs (depends on dispatch/settlement design and access for flexibility resources)
Storage build-out but constrained monetisation	Makes the 'hard-to-supply hours' explicit, enabling differentiated value for time-shifted clean delivery	May support revenue stacking and bankability for firmed products (depends on market access, ancillary/capacity mechanisms, and clear anti-double-counting rules)
Rising scrutiny of claims in trade-linked regimes and voluntary standards	Creates auditable, time-stamped evidence that can be linked to metering and settlement records	Improves credibility and comparability of claims (depends on data governance, verifier access, and registry/contract standardisation)

GETTING STARTED: NEAR-TERM IMPLEMENTATION TO-DOS

- Define the specific claim(s) in scope (annual, monthly, hourly matched, 'RTC-style') and the minimum evidence package required for each (metering, settlement, registry retirement, audit trail).
- Select priority provinces and use cases based on readiness (spot market maturity, data availability, concentration of relevant buyers, and feasibility of contracting pathways).
- Identify data access routes for settlement-grade interval data and clarify governance (who can access what; verifier role; formats; retention; privacy/security).
- Map contracting structures that can be executed under current retail rules (including retailer-mediated or tripartite structures) and specify deviation/curtailment treatment.
- Design how time-stamped evidence will be linked to GECs (e.g., a timestamp 'layer' reconciled to monthly totals) and specify anti-double-counting controls, especially where storage or portfolio firming is involved.
- Run limited-scope pilots, publish lessons learned, and iteratively standardise definitions and templates (claim language, verifier checks, data schemas, and registry procedures).

01.

CHINA POWER SECTOR OVERVIEW

This chapter provides the essential context for the rest of the report. RTC-style clean power procurement and granular matching are ultimately constrained (or enabled) by how electricity is scheduled, traded, settled, and retailed in China today, including who is exposed to time varying prices, what data signals are created through metering and settlement, and how physical delivery is executed across provincial and interprovincial transactions. The aim here is therefore not to recap market history for its own sake, but to clarify the institutional and operational building blocks that later sections draw on to assess the practical feasibility of more time resolved clean electricity claims.

Sections 1.1–1.3 are intentionally abridged to focus on the minimum market context needed for the RTC and granular matching discussion that follows. A fuller reform narrative and additional background is provided in Appendix B. With this market "primer" in place, Chapter 2 then turns to the supply side and the policy mechanisms shaping renewable generation and procurement in China.

1.1. CHINA'S POWER MARKET TODAY

1.1.1. STATE OF MARKETISATION

China's power sector today is best understood as a hybrid between a still mostly centralised administrative system and a gradually deepening set of market mechanisms. In practice, market-based trading has expanded rapidly, but dispatch and grid-security functions remain centralised, and many key rules are still set administratively

For RTC style procurement, the key constraints are in the market mechanics: what is traded and settled at short time intervals, who is exposed to time varying prices, what metering and settlement data exist (and can be accessed), and how delivery is executed.

1.1.2. HOW POWER IS TRANSACTED

For the purposes of this report, the following features describe where China's power markets have "landed" by early 2026:

- **Mid/long term (MLT) contracting remains the foundation of traded volumes.** MLT contracting continues to anchor wholesale outcomes and remains the main risk management tool for both generators and buyers. Even in provinces with formal spot market operation, most energy is still procured through MLT arrangements, with spot settlement only beginning to act as the mechanism that prices deviations and reveals intra day scarcity or oversupply, which are increasingly driven by output variation from renewable generators, such as solar concentrated in daylight hours.
- **Spot markets are progressing, but unevenly, and administrative constraints are still meaningful.** Spot reform is advancing province by province, strengthening time varying price and settlement signals where implemented. As of Q1 2026, seven provincial spot markets have entered formal operation, with many others still in trial. At the same time, price formation remains shaped by administrative design choices (including price caps, benchmark anchoring, and provincial implementation differences), so spot market existence does not automatically translate into full transparency or full buyer exposure to short term price signals.
- **Retail procurement is increasingly market based for C&I users, but exposure to temporal pricing is mostly indirect**. Most eligible commercial and industrial users procure electricity through licensed retailers and standard retail menus that translate wholesale outcomes into buyer facing prices under province specific rules. This current arrangement hinders attempts to make granular claims because a buyer can only practically contract (and prove) time resolved supply if their retail arrangements also support time resolved settlement and data access. Where retail contracting remains mainly monthly in structure, the system can still produce granular dispatch and settlement outcomes "in the background" without creating a straightforward pathway for corporate buyers to make time matched claims.

For most commercial and industrial users (i.e., other than large direct wholesale buyers), the practical interface is the retail layer, where licensed retailers transform wholesale outcomes into buyer facing contracting structures. Because many retail arrangements remain structured around monthly settlement and standard pricing menus, short interval wholesale price signals and dispatch outcomes are typically not directly visible or contractible for end users.

1.2. CHINA POWER MARKET STRUCTURE AND OPERATION

1.2.1. GOVERNANCE AND INSTITUTIONAL ROLES

China's power market is structured as a layered system sitting atop a still centralised dispatch and grid security framework. This structure determines where decisions are made (national vs provincial), which entities control dispatch and settlement, and how market outcomes are transferred into buyer facing retail contracts.

As with Section 1.1, the focus here is on the current operating structure; the longer reform narrative is provided in Appendix B.

At the top level, the State Council sets the strategic direction, while the National Development and Reform Commission (NDRC) and National Energy Administration (NEA) shape market reform, pricing policy, and implementation guidance. At the provincial level, Development and Reform Commissions (DRCs) and energy authorities translate these directives into local market rules, tariff arrangements, and trading products. Operationally, grid companies and dispatch organisations remain responsible for system security and real time balancing, while power exchanges organise trading, clearing, and (in most provinces) settlement calculations. Even where markets are relatively competitive on paper, dispatch constraints and administrative design choices can substantially affect realised price and delivery outcomes.

1.2.2. GEOGRAPHIC HIERARCHY AND DELIVERABILITY BOUNDARIES

The province is the core unit of power system operations in China. Most balancing, dispatch coordination, and retail rulemaking are provincial, meaning that the same procurement concept (e.g., an hourly matched product) might be feasible in one province but not in another, depending on spot market maturity, metering systems, and the degree of retail exposure to time varying settlement. Above the provincial layer, interprovincial and regional trading mechanisms enable large power flows between resource rich and load rich areas, but these trades are often constrained by planned transmission utilisation, limited transparency on available transmission lines, and operational adjustments following market clearing. For clean electricity claims, this makes deliverability and evidence requirements inherently jurisdiction and route specific.

1.2.3. MARKET LAYERS AND THE BUYER INTERFACE

Commercially, the market is best understood in layers. MLT contracts anchor most traded volumes and provide the primary risk management tool for participants. Spot markets (day ahead, and in some provinces intra day) increasingly set deviation prices and reveal hour to hour scarcity or oversupply, but maturity and transparency still differ widely across provinces, and administrative constraints can shape outcomes.

For most commercial and industrial users, the retail layer is the practical point of interface with wholesale outcomes. Procurement is typically mediated by licensed retailers and settled on monthly cycles, with menu style structures that simplify wholesale outcomes into buyer facing prices. The degree to which buyers are exposed to short interval settlement signals therefore varies significantly by province and by contract type.

With this structural context in place, Section 1.3 summarises the basic transaction lifecycle (contracting, scheduling/dispatch, and settlement) that links wholesale trading to what buyers ultimately pay and what records are produced.

1.3. HOW POWER IS TRADED, SCHEDULED, AND SETTLED

1.3.1. CONTRACTING (MLT, CPPAS, AND RETAIL PRODUCTS)

This section summarises how China's electricity transactions translate into operational outcomes: what is contracted, what is scheduled, what is dispatched, what is settled, and what records are created in the process. For RTC-style claims, the key point is whether a buyer can assemble a clean, auditable trail that links metered consumption to settlement allocations (including deviations) and to the green attribute instrument used for the claim.

MLT contracts anchor volumes, but do not replace real-time dispatch. MLT trading remains the foundation of power transactions and the main risk-management tool for both buyers and generators. These contracts are generally treated as forward (financial) arrangements: they define contracted volumes and pricing, but physical dispatch is still executed by dispatch organisations based on system conditions and security constraints. In practice, this means MLT outcomes need to be read together with spot settlement and deviation settlement to understand what was actually delivered (and what evidence exists for time-resolved claims).

1.3.2. SCHEDULING AND DISPATCH

Spot markets are where real temporal price and settlement signals emerge, but access and maturity vary. In provinces with spot market operation, the market design typically includes a day-ahead stage, followed by intra-day adjustments, with real-time balancing performed by the system operator at short intervals (as short as 15 minutes in several provinces). In practice, the day-ahead market is the most consistently available component; intra-day markets are still uneven and are sometimes used only under system stress or executed via dispatch instructions rather than continuous trading. Real-time operation is primarily a balancing tool and is not yet widely tradable or transparently settled for end-users. Nevertheless, spot settlement is still relevant because it prices deviations around MLT schedules and reveals scarcity or oversupply on an hour-by-hour basis.

1.3.3. SETTLEMENT AND DEVIATIONS

Deviation settlement is the bridge between contracts and reality. Because dispatch and forecasting conditions change continuously, actual generation and consumption will rarely match contracted schedules exactly. The difference is handled through deviation or imbalance settlement, which is increasingly linked to spot prices in provinces with operating spot markets. This has two implications for RTC-style procurement. First, it is a key part of the auditable record of "what happened" in each hour, because it creates a history of short-term imbalances. Second, it is where many firming concepts become real (or fail to): if a buyer seeks a time-shaped clean product, the treatment of deviations and curtailment adjustments determines whether the product can be reconciled credibly to meter data and settlement outcomes.

The retail layer is the buyer-facing interface. Most commercial and industrial users participate through licensed retailers, with procurement typically negotiated on annual cycles and settled on monthly billing periods. Retail "menu" structures translate wholesale outcomes into buyer-facing prices, so end-user visibility of short-interval settlement can be limited even where spot markets exist.

1.3.4. GENERATION OF RECORDS

Electricity transactions generate several record types (e.g., interval metering data, settlement statements, and retail invoices). Which of these are accessible to buyers and suitable for third party verification varies by province and customer segment. The implications for clean attribute claims and time-resolved approaches are addressed in Chapter 3 (GECs and claim rules) and Chapter 6 (implementation pathways and MRV requirements).

In summary, China's market is increasingly capable of producing time-resolved operational and settlement signals but translating those signals into buyer-facing RTC-style procurement depends on retail contracting pathways, access to interval data, and consistent reconciliation across metering, settlement, and certificates. With that market context in place, Chapter 2 turns to the supply side: how renewable generation has been incentivised and integrated, what policy mechanisms shape renewable procurement (including green power trading and corporate PPAs), and what constraints in renewable buildout are now emerging as renewables move deeper into market-based pricing and settlement.

02.

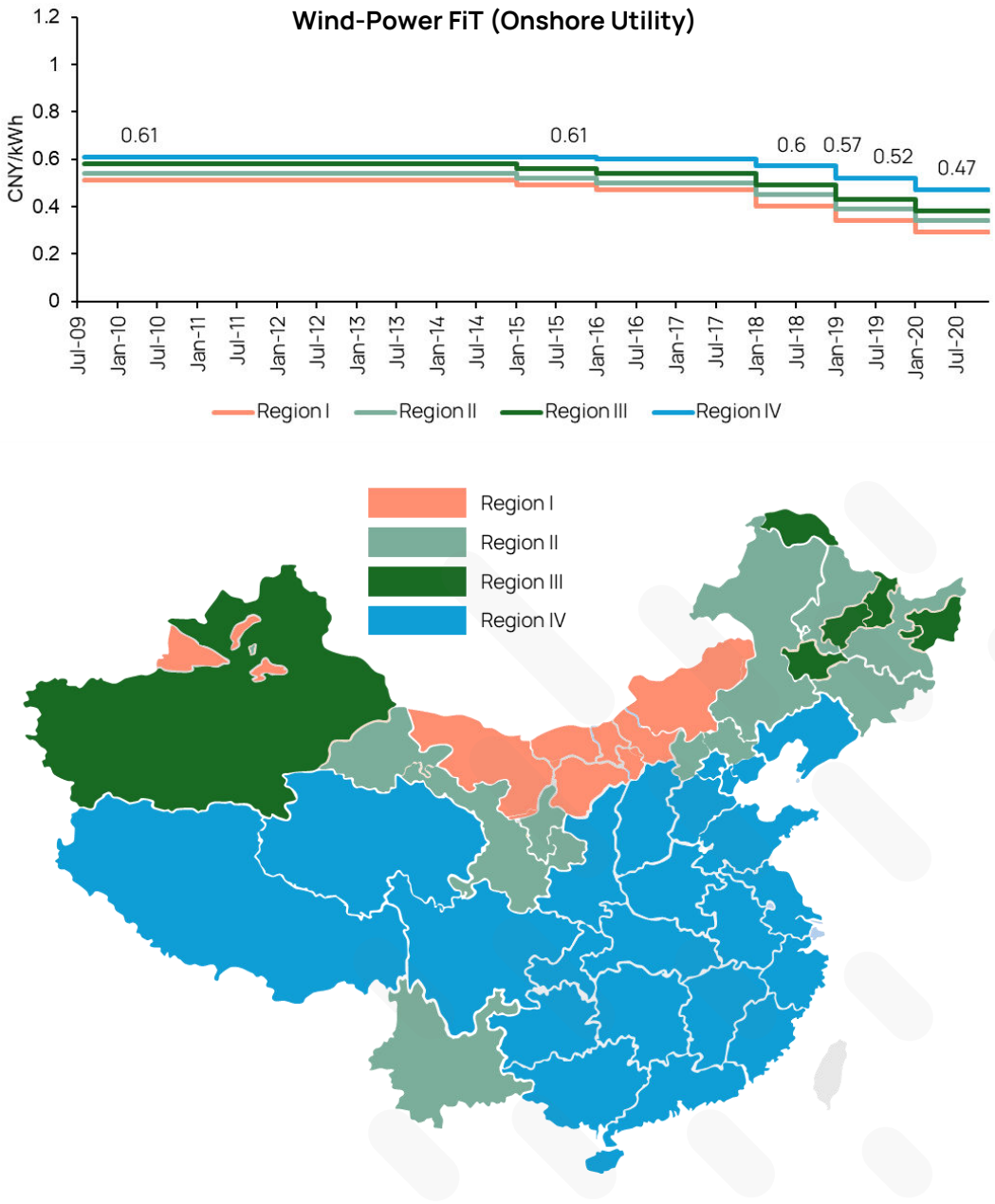
RENEWABLE POWER IN CHINA

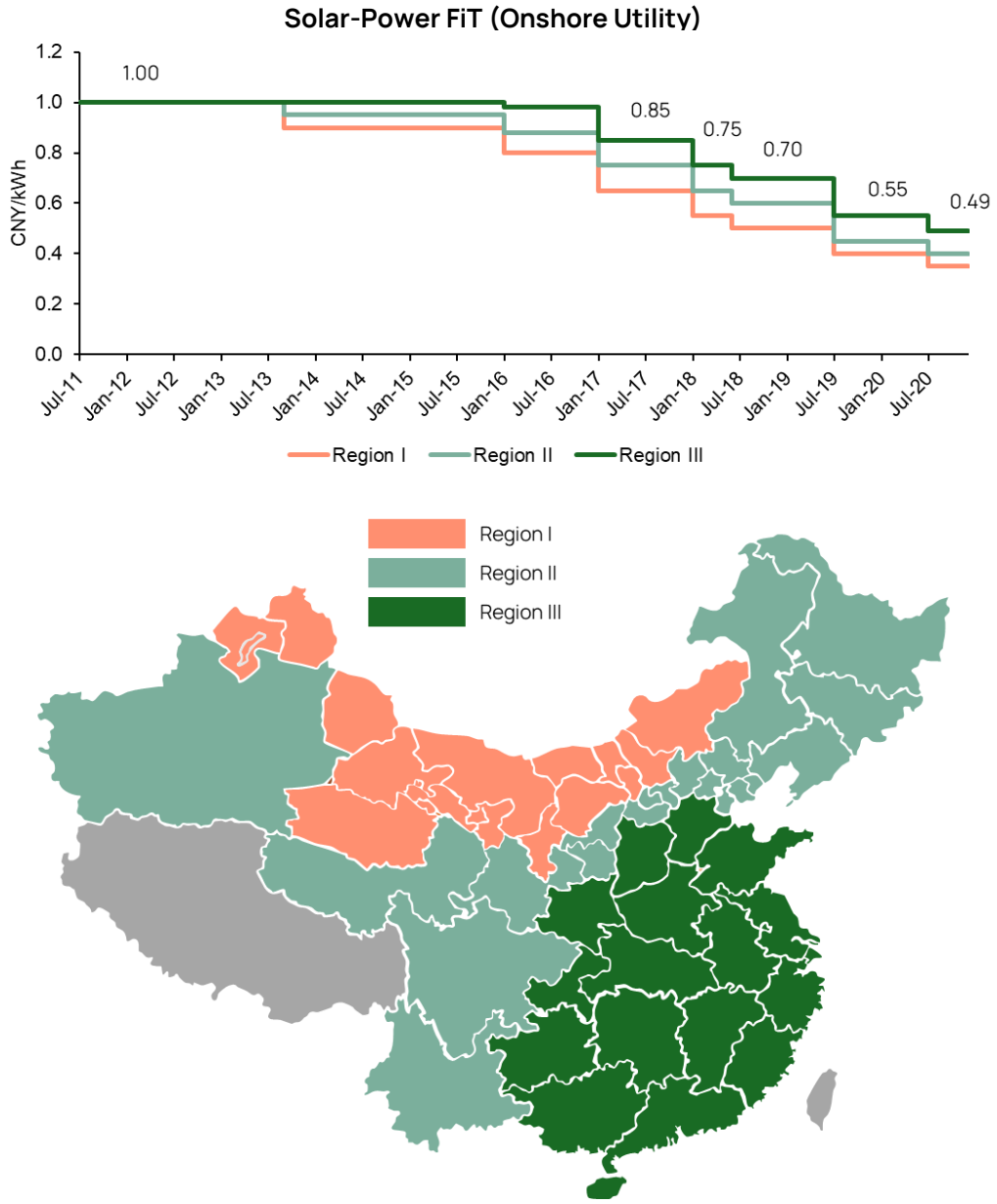
2.1. SUPPLY-SIDE SUPPORT FOR RENEWABLE ENERGY

2.1.1. SUBSIDY FEED-IN TARIFF ERA

From 2009 to 2020, China used a Feed-in-Tariff (FiT) subsidy scheme to encourage the development of renewables. This FiT comprised two portions: a base compensation equal to the prevailing coal on-grid benchmark price (paid by the grid company), and a subsidy portion funded via an end-user surcharge on C&I electricity customers. FiT levels were differentiated across provinces based on the quality of local wind and solar resources. Renewable projects built during the FiT subsidy era generally enjoyed priority dispatch with the intention of guaranteeing their generation offtake, although overbuilding and line congestion would eventually still lead to curtailment problems during the mid-2010s.

Figure 1: Wind and Solar FIT Evolution in China





Source: The Lantau Group

With FiTs starting at generous levels in 2009, capacity expansion and industry scaling were brisk, with technology costs falling rapidly. Solar FiTs were adjusted for the first time in 2013, followed by wind FiT adjustments in 2015. Over the latter half of the decade, FiT levels for both wind and solar were gradually adjusted downward across all regions until the subsidy component declined to nearly zero.

In the final years of the FiT subsidy era, the value of the subsidy portion was determined via a competitive allocation mechanism (i.e., a reverse auction) rather than fixed by policy, and subsidy-free "grid-parity" projects began to appear, receiving contracting or dispatch-related perks and benefits for choosing to forego subsidy support. FiT compensation was generally uniform within each category and did not differentiate by hour of generation, reflecting a policy emphasis on deployment volumes rather than temporal system value.

2.1.2. GRID-PARITY FEED-IN-TARIFF ERA

By 2021, grid-parity Feed-in-Tariffs became the standard compensation mechanism for China's newbuild wind and solar projects, replacing the subsidy scheme (which continued to be paid out to older projects). Under the grid-parity FiT scheme, wind and solar generators received dispatch compensation equal to the local coal-fired base price, with no additional subsidy component. Early policy indicated grid-parity projects would be eligible for 20-year offtake agreements, although this was later revised. Although dispatch was guaranteed, the annual offtake volumes were not unlimited. "Annualised reasonable utilisation hours" were introduced which capped the hours eligible for guaranteed grid-parity compensation. Any generation beyond these contracted volumes could be sold in the emerging power markets.

In the grid-parity era, as in the earlier FiT regime, the grid company remained the counterparty, compensating generators directly at the benchmark price, but without an end-user surcharge to fund payments. Notably, this compensation scheme persisted even after 2021's Document No. 1439 pushed coal-fired generators fully into the power markets. As a result, although renewable generators were no longer receiving fixed subsidies, they continued to earn policy defined dispatch prices that diverged from market rates earned by other generators. During 2021-2022, when coal prices were elevated, so-called 'grid parity' generators' compensation was materially lower than market prices; by contrast, during 2023-2024, grid-parity compensation consistently exceeded market prices. The gaps between grid parity compensation and the prevailing market prices highlighted the limitations of benchmark anchored tariffs, setting the stage for a transition toward market cleared pricing mechanisms.

2.1.3. POST-FIT MARKET PRICING AND THE INTRODUCTION OF CFDS

In early 2025, the release of Document No. 136 marked a decisive shift toward full market-based offtake for renewable generation.[1] All projects connected to the grid before 1 June 2025 were designated as "pre-existing projects", becoming eligible to sign Contracts for Difference (CfDs) with the grid company. This mechanism applied retroactively to grid-parity projects commissioned between 2021 and 2025, with CfD strike prices typically benchmarked to the prior guaranteed offtake rate (i.e., the local coal-fired base rate). In effect, this arrangement preserved continuity in project revenues while requiring generation to be sold into the power markets, strengthening the price discovery function of the markets while neutralising revenue volatility.

For newbuild projects, CfD strike prices are now determined via competitive auctions, with provincial policymakers setting the total volume of generation eligible for CfDs based on local conditions and renewable energy consumption targets. All generators with CfDs now sell their generation into the open power markets, with the grid company settling the difference between the prevailing market rate and the contracted price. These difference payments are funded via a fee collected from C&I power buyers, similar to the original renewable development surcharges levied in the FiT subsidy era.

Document No. 136 transitioned renewable generation into market-cleared pricing while stabilising project revenues via a CfD settlement mechanism. This change increased the relevance of time-varying electricity value, signalling a clear need for green flexibility and energy availability when and where buyers most appreciate it.

1. NDRC & NEA, *Notice on Further Deepening the Market-oriented Reform of On-grid Tariffs for New Energy and Promoting High-quality Development of New Energy,* NDRC Price [2025] No. 136.

The FiT scheme and the CfD scheme imposed no requirement on flexibility, leading to massive solar and wind capacity growth while the demand pattern changed and the grid network development could not keep up with their speed, which led to cannibalisation of renewables. While there was a short period of time when building generation-side battery was part of the requirement of applying for renewable capacity quotas, this was later removed when the CfD scheme was announced. Since 100% of renewable volumes are now exposed to spot market settlement, they are now receiving clear signals about renewable oversaturation (especially when markets settle at CNY 0/kWh during maximum solar output). These pricing signals push renewable operators to actively manage their hourly dispatch profiles, secure PPAs for stable income and improve forecasting accuracy.

2.2. DEMAND-SIDE POLICY SUPPORT FOR RENEWABLE ENERGY

2.2.1. RENEWABLE PORTFOLIO STANDARD: DESIGN AND CORE IMPLICATIONS

China's Renewable Portfolio Standard (RPS) was introduced in 2019 as a renewable power consumption quota system. It initially applied to wholesale market participants, including grid companies, electricity retailers, and large wholesale power buyers. Quota levels were modest in the early years and differentiated by province, reflecting regional variation in wind and solar resources. Over time, both the scope and ambition of the RPS have expanded. Responsibility for compliance has increasingly shifted from supply-side entities towards the power customers themselves, especially energy intensive industrial users like cement, steel, and polysilicon producers. In parallel, annual RPS targets have been raised steadily in line with China's rapid renewable capacity expansion. In 2025, the average provincial RPS level for obligated entities was 37.5%, ranging from 24.2% on the low end (Fujian) to as high as 70% on the high end (Sichuan/Yunnan/Qinghai).

To date, the RPS represents the strongest demand side policy driver for renewable energy in China. Critically, however, the RPS is purely volumetric: it specifies how much renewable electricity must be consumed, but not when or where that electricity is generated. As a result, RPS demand in load heavy but resource constrained provinces (like Guangdong, Jiangsu, or Shanghai) can be satisfied by renewable generation from resource rich regions that face curtailment risk. This design has facilitated large scale interprovincial renewable flows, improved national resource allocation, and reduced wind, solar, and hydropower curtailment during the early stages of rapid capacity growth.

The volumetric nature of the RPS has also supported the development of China's GEC market. Because RPS obligations can be fulfilled using unbundled GECs, the RPS provides a stable source of demand for certificates and helps establish GECs as a core compliance instrument. The early RPS design with obligations imposed primarily on grid companies and retailers (rather than directly on end users), kept compliance relatively straightforward and contributed to rapid market acceptance.

2.2.2. RPS STRUCTURAL LIMITATIONS, CANNIBALISATION, AND POLICY EVOLUTION

While it has been effective at scaling renewable consumption, the RPS lacks temporal and locational differentiation. This means that under the RPS, solar and wind generation from different regions and produced at different times is treated as economically identical. As renewable capacity expanded, this design led to cannibalisation effects, especially for solar projects. Cannibalisation is largely a temporal phenomenon with surplus solar output concentrating in the same midday hours, depressing prices and raising the likelihood of curtailment. This shifts the nature of China's renewable buildout challenge to a question of renewable integration, which in turn increases the importance of storage, demand flexibility, and more time-resolved procurement and verification approaches.

In practice, several renewable-rich provinces (including Shanxi, Hubei and Chongqing) fell short of their RPS targets in 2024. While curtailment can contribute to lower realised renewable consumption in regions with relatively abundant renewable resources, RPS non-compliance can also reflect constraints in grid infrastructure, local demand growth, and the practical limits of transmitting renewable generation to obligated consumers.

These dynamics are most visible in renewable-surplus western regions, where development has outpaced local load growth and the transmission system's ability to export generation, contributing to the re-emergence of high solar curtailment in 2025 (35% in Tibet and 14% in Xinjiang). As western regions increasingly depend on eastern provinces to absorb surplus generation, importing provinces' rapid buildout of local solar can intensify midday oversupply and weaken project economics.

Because electricity must be consumed at the time it is generated, imported solar from western regions increasingly competes with local solar generation in importing provinces, most acutely around midday when solar output peaks. Even higher RPS targets in importing provinces cannot fully resolve this issue, as the constraint is temporal and system based rather than purely volumetric. Addressing the next phase of renewable integration therefore requires mechanisms that recognise when clean electricity is delivered (and consumed), not only how much is delivered over a month or year.

Recognising these limitations, Chinese regulators have begun to evolve the RPS framework. In 2024, RPS obligations were extended explicitly to high-consuming corporate electricity consumers, starting with the electrolytic aluminium industry. In 2025, the *"New Energy Consumption and Control Guiding Opinion"* introduced further reforms, emphasising coordination between regional RPS targets, grid capacity, dispatch capability, and local renewable development. The policy signals a shift away from a single utilisation rate metric toward integrated indices that more comprehensively assess renewable system health. Thanks to the volume quotes in the new CfD mechanism, the expansion of local distributed renewable development is now coupled with RPS targets, discouraging excessive or indiscriminate capacity expansion.

2.2.3. GREEN CORPORATE PPAS

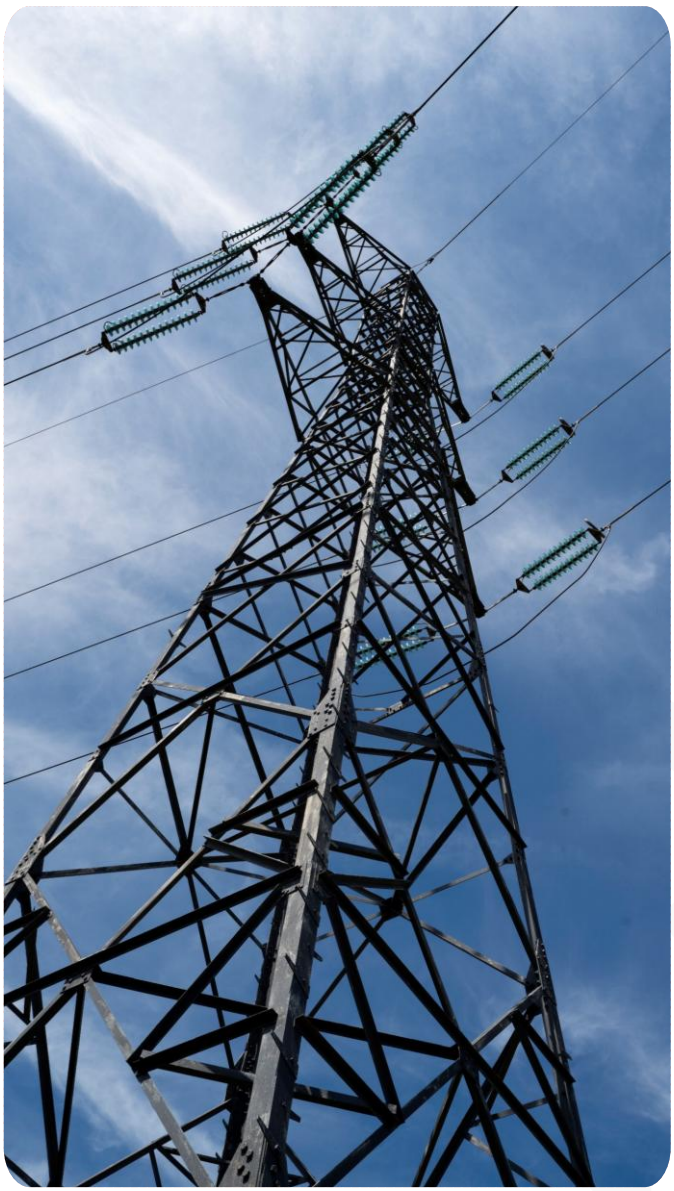
Corporate PPAs have historically played a limited role in China, reflecting the grid company and, more recently, licensed retailers serving as the dominant counterparties. Only in the last several years have green corporate PPAs emerged as a potential offtake channel, driven by rising RPS quotas and the marketisation of renewable generation; however, uptake remains limited so far. Public information on green corporate PPAs in China is limited. Announcements typically confirm the participating parties, location, and (sometimes) contract tenor or intended supply source, but commercial terms (including pricing, volume structure, and allocation of imbalance or curtailment risks) are generally confidential and should not be inferred from public disclosures.

A clearer public example, closer to the international CPPA concept, was Danfoss' April 2024 announcement of a 20 year green power purchase framework cooperation agreement with CGN New Energy (Zhejiang) Co., Ltd for its Haiyan campus. The agreement covered green electricity trading volumes for 2025–2044 and is supplied from CGN's Zhejiang-based renewable projects, including the Haiyan Port tidal-flat photovoltaic project and the Cixi offshore wind project in Ningbo. Commercial terms were not disclosed. This example notwithstanding, a 20 year CPPA term is very uncommon in the current China context; multi year corporate renewable procurement agreements more typically fall in the 3-10-year range.

Corporates more commonly procure green electricity through retail contracts with licensed retailers. These arrangements remain the dominant channel for most buyers, while a distinct pathway for "direct" green supply projects (including dedicated connection arrangements) is discussed in the next section.

2.2.4. DIRECT GREEN POWER SUPPLY PROJECTS

Released in May 2025, Document 650 established the first national framework for direct green power supply projects.[2] These projects allow an end-user to take a majority ownership stake in a renewable generation asset and supply electricity primarily to its own facilities, while in provinces with operating spot market retaining the option to export surplus power to the grid. As a complementary measure, Document 1192 issued in September 2025 clarified the applicable pricing arrangements for corporates and generators participating in green direct supply, particularly with respect to the calculation and allocation of transmission and distribution (T&D) tariffs.[3]



By the end of 2025, more than ten provinces had issued formal or draft implementation policies dealing with the implementation for direct green supply projects, reflecting different regional priorities while aligning closely with provincial industrial strategies. In some cases, green direct supply is targeted at export-oriented industries like batteries and chemicals to address CBAM exposure and enhance supply-chain traceability. In resource-rich provinces, it supports resource-conversion industries such as electrolytic aluminium, hydrogen, and polysilicon, transforming local renewable resources into higher-value manufacturing output. In more developed regions, it is positioned as a tool to facilitate industrial upgrading, particularly for data centres and semiconductor manufacturing. Provinces like Inner Mongolia, Jiangsu, Xinjiang, and Yunnan have collectively approved over 50 green power direct supply demonstration projects, while Ningxia has launched the country's first cross-provincial green power direct supply project, enabling a new procurement channel for end-user offtakers.

2.3. CHALLENGES FOR THE RENEWABLE BUILDOUT

The main challenges discussed in this section, namely curtailment, negative pricing, and pressure on renewable project profitability, should not be treated as three separate problems. They are closely related manifestations of the same underlying tension: renewable capacity is being built faster than the grid, market arrangements, and operational flexibility can absorb it, while existing green accounting remains predominantly volumetric and therefore weakly connected to the hours in which the system is over- or under-supplied. Limited sources of flexibility (e.g., storage or demand response), highlight the system's weak ability to shift surplus renewable output to other periods of time, which in turn increases curtailment risk and depresses realised prices. These challenges help highlight how time-resolved approaches, including granular clean energy matching, are relevant as part of the next phase of renewable integration.

2. NDRC & NEA, *Notice on Orderly Promoting the Development of Green Power Direct Connection*, NDRC Energy [2025] No. 650.
3. NDRC & NEA, *Notice on Improving the Pricing Mechanism to Promote Local Consumption of Renewable Energy Generation*, NDRC Price [2025] No. 1192.

2.3.1. CURTAILMENT

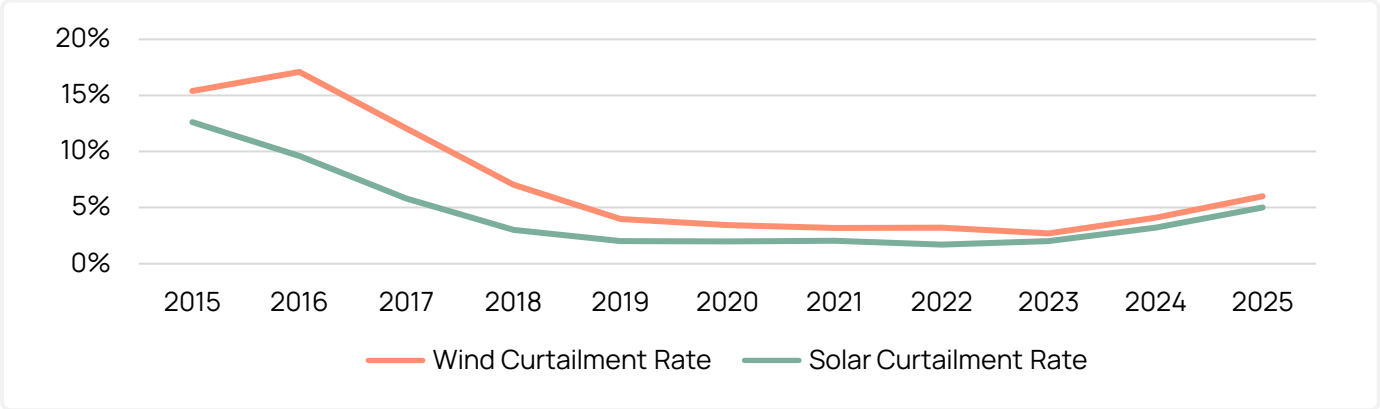
Curtailment in China's renewables sector emerged in distinct phases. Wind curtailment emerged for the first time around 2010, with hydropower curtailment appearing around the same period (especially during rainy-season surpluses). Solar curtailment began appearing slightly later, around 2015. Wind curtailment levels averaged roughly 10-17% during 2010-2016, while average solar curtailment reached 12% by 2015. In Sichuan, hydropower losses were reported to be as high as 15% of seasonal output in 2013. Conditions improved after monitoring enhancements and policy interventions. These included the establishment of dedicated curtailment tracking, and an explicit shift away from indiscriminate capacity expansion (including newbuild moratoriums in the worst-affected regions). Measures such as RPS targets and demand response schemes also played a (smaller) role.

Curtailment risk is now re-emerging as capacity additions since 2024 have once again outpaced the power system's ability to absorb such large amounts of new generation. While new renewables are displacing thermal generation, they are also competing with other sources for dispatch in the same hours. Further reforms are needed for wind and solar capacity additions to remain at high levels – especially improved system planning, deepening of market-based dispatch and price signals, and strong investment in flexibility resources (including storage). Additionally, wider adoption of hourly green-attribute tracking (e.g., granular certificates) could support curtailment reduction by making the timing of renewable generation visible and verifiable to buyers, retailers, and (where relevant) regulators.

The drivers for curtailment in the mid-2010s were primarily structural. Wind and solar capacity expanded more rapidly than local demand growth and the system's capacity to absorb generation variability. Additionally, end-users had limited incentives to shift their consumption patterns and interprovincial transmission infrastructure lagged the capacity buildout. UHV lines require at least 3-5 years from planning to commissioning, while wind and solar projects can be built in just 1-2 years. Local grid network upgrades also trailed the demand created by large-scale injections of variable renewable output.

Institutional coordination challenges exacerbated the physical constraints. Even in cases where inter-provincial transmission capacity existed, importing provinces were reluctant to accept large volatile power flows that could stress system stability. As a result, wind and solar curtailment was most severe in traditional power-exporting regions with weak local load growth like Qinghai, Xinjiang, Gansu, and Inner Mongolia, along with hydropower in Sichuan and Yunnan. Renewable generators suffered significant financial losses due to curtailment during this period, as their compensation was based on dispatch hours.

Figure 2: China Wind and Solar Curtailment Rate 2015-2025



Source: NEA, The Lantau Group analysis

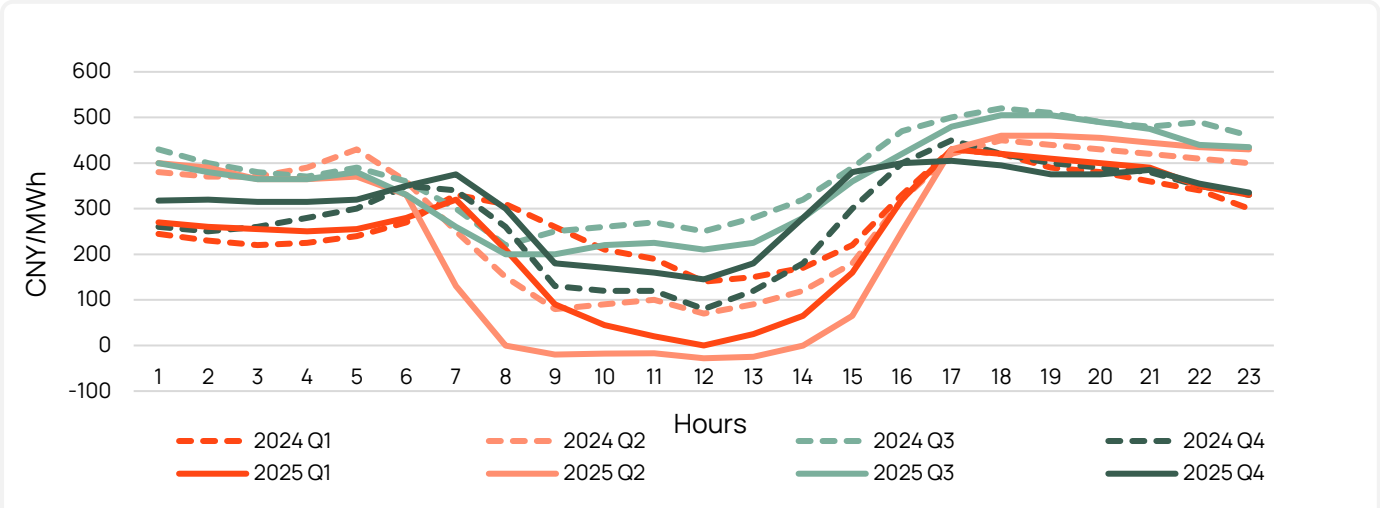
In turn, time-matched procurement creates incentives to shift flexible demand toward high-output periods and invest in assets that can transfer renewable generation into higher-value hours (including most prominently storage, but also firmed portfolios). Where these measures reduce the concentration of surplus generation in oversupplied hours (particularly at midday for solar), the system requires fewer curtailment actions and renewable projects capture higher realised utilisation and revenues.

2.3.2. VERY LOW AND NEGATIVE MARKET PRICES

Even if renewables manage to avoid curtailment and secure dispatch, they also face growing exposure to very weak or even negative prices in short term power markets. Negative pricing in China has emerged as a byproduct of rapid renewable expansion combined with inflexible system operations and increasingly market based spot settlement. Shandong provides a stark illustration: in 2025, its average spot power market settlement rate was negative for every hour of the day between 8am and 4pm throughout all of Q2. In periods of high wind, solar, or hydropower output, especially during low demand hours, renewable generation can exceed the system's ability to absorb energy through demand, storage, or exports. When combined with must run thermal units and limited short term flexibility, this oversupply places severe downward pressure on clearing prices. Public disclosure of hourly settlement prices remains uneven across provinces while the spot markets are still broadly immature, so comparable time series are not consistently available nationwide.

Negative prices remain periodic and regionally concentrated, but their frequency has increased as more provinces introduce spot markets and expose generators to marginal pricing. While occasional periods of negative pricing can be normal and even useful features in healthy power markets, extended periods of negative pricing typically indicate more fundamental power system weaknesses.

Figure 3: Shandong Day-ahead Spot Market Quarterly Average Prices



Source: Shandong Power Exchange, The Lantau Group

For renewable projects, weak market prices create a new revenue risk: energy may be dispatched but settled at prices that are insufficient to cover operating costs or, in extreme cases, require generators to pay to remain online. As a result, overcapacity shifts the challenge from physical curtailment toward economic curtailment, underscoring the importance of flexibility, demand response, and improved price formation in managing high renewable penetration. It is also a reminder that a volumetric green power paradigm is increasingly misaligned with system realities, hence the need for hourly matching.

2.3.3. PRESSURE ON PROJECT PROFITABILITY AND BANKABILITY

China's green power prices have fallen consistently since 2022, including a compression of the green premium relative to the price of brown power. This trend has been reinforced by rapid renewable capacity expansion, the emergence of spot market price volatility (including weak and occasionally negative prices), and the implementation of Document No. 136, which has reduced guaranteed volumes and increased developers' exposure to market outcomes.

In response, power buyers increasingly anticipate further price declines and have adopted more assertive negotiating positions, while showing greater reluctance to commit to long term fixed price contracts like multi-year PPAs. In provinces with active spot settlement, this also creates a hedging challenge: solar-linked PPAs primarily deliver in already-weak daytime hours and therefore provide limited protection against price risk in the higher-priced hours when solar output is low. However, available evidence suggests that these pressures have not yet translated into materially tighter financing conditions. Recent interviews with developers indicate lenders continue to anchor credit assessments primarily on sponsor strength, balance sheet quality, and policy continuity, rather than on the presence of long term corporate PPAs. While profitability pressuresare clearly rising, their impact on bankability appears, at least for now, to be indirect, suggesting a lag between marketisation risk and its consideration in financing practices for renewable projects in China. This should not be read as implying that merchant-only financing has become standard; rather, CfDs (where available) and sponsor balance sheets remain the dominant stabilisers as market exposure increases.

Figure 4: Historical Green Power Price

Source: Provincial power exchanges

03.

GREEN ENERGY CERTIFICATES

Chapter 2 highlighted how renewable value is increasingly shaped by market dynamics, including declining green premiums and growing pressure on project revenues. In this environment, the credibility and design of green attribute tracking have become more meaningful. Because the value of a green attribute – which is an inherently abstract product - is institutionally constructed through market design, the credibility and reputation of the tracking instrument directly influence the trade of renewable energy. More specifically, the rules governing certificates determine what buyers can credibly claim, how renewable consumption is accounted for, and how any green premium is priced.

Chapter 3 thus turns to China's GEC system, which has evolved from its early years as a small voluntary pilot into the central instrument for renewable attribute issuance and retirement, and the key foundation for any future move toward more time-resolved claims.

3.1. GEC POLICY REFORM

3.1.1. HISTORICAL DEVELOPMENT OF GECS

China's GEC is the only recognised national renewable energy certificate. It functions as a blockchain-based digital instrument representing the environmental attributes of 1 MWh of electricity generated from renewable sources. Today, GECs are issued for all renewable generation types, including wind, solar, conventional hydropower, biomass, geothermal and marine energy, following the implementation of the 2023 "full coverage" policy. Over the years, China's GEC has evolved through phased policy reforms, starting as a voluntary pilot into the key regulatory mechanism governing how renewable energy attribute is tracked, traded, and claimed across China.

The GEC system was officially launched in 2017 by the Renewable Information Management Center (RIMC), a subsidiary of the NEA. In its initial phase, it functioned as a voluntary subscription and subsidy-alternative revenue channel, issuing certificates exclusively to subsidised onshore wind and utility-scale solar projects to alleviate cash flow pressures from delayed subsidy payments.

These early Subsidy-Alternative GECs were priced at the level of the foregone subsidies, ranging from USD 32-95/MWh, which proved unattractive to most market buyers. The high price, combined with weak voluntary demand and no policy compliance demand resulted in very low transaction volumes. For instance, according to the NEA's *GEC Development Report* published in 2025, between 2017 and 2020, nearly 30 million GECs were issued, yet fewer than 42,000 were traded. Just 1% of the estimated 2,300 TWh of renewable power generation over the 2017-2020 period saw corresponding GEC issuance, and a negligible fraction of those GECs would actually go on to be traded.

In 2019, the GEC issuance scope was expanded to include grid-parity wind and solar PV projects, creating a new Grid-Parity GEC product with a more market-aligned price. This marked the beginning of the system's decoupling from subsidy dependency. In contrast to the Subsidy-Alternative GECs, these new instruments were priced far more modestly, reflecting buyers' true willingness to pay a green power premium. Prices dropped rapidly, and by 2022 a Grid-Parity GEC cost just USD 8/MWh. The concurrent implementation of the RPS and subsequent launch of the Green Power Trading Pilot Programme in 2021 established a market structure for green compliance based on GECs. Then in November 2022, a new policy clarified GECs could also serve as a compliance instrument within the "dual control" energy consumption/intensity cap system, allowing provinces to use GECs to offset any energy consumption exceeding the allocated limits.[4]

3.1.2. GECS IN THE MODERN ERA

The most transformative development for GECs arrived in August 2023 with the release of NDRC Document No. 1044. This policy designated the GEC as the key instrument for demonstrating green attributes in China, including for certifying and consumption green electricity, resolving prior ambiguities and concerns over double-counting with other instruments.[5] It mandated the issuance of GECs to all renewable energy sources, elevating the GEC's role from a supplementary instrument to the central, legally recognised pillar of China's green attribute tracking system.

This transformation was institutionalised in August 2024 with NEA Document No. 67, which confirmed GECs as the sole instrument for domestic RPS compliance, excluding all international and provincial-level certificates.[6] The Electric Power Business Qualification Management Center under the NEA became the issuing authority, while the RIMC shifted to a technical support role. GECs may now be traded via bilateral negotiation, listing, or auction – but only once, with no secondary trading among end-users. A key coordination policy was introduced that same month by the NEA and MEE, establishing a "choose one" mechanism between GECs and China Certified Emission Reductions (CCERs).[7] A few months later, in China's first-ever Energy Law, GECs were recognised as a foundational mechanism for promoting renewable energy consumption.

Following the elevated prominence of the GEC as the sole recognised renewable consumption compliance instrument in China, the I-TRACK Foundation announced the cessation of new International Renewable Energy Certificate (I-REC) issuance for registered Chinese renewable assets from March 2025. In that same month, the NDRC's Document No. 262 outlined a roadmap to fully establish the GEC market by 2027 and refine it by 2030.[8] Key measures included implementing a GEC cancellation mechanism for the first time, extending RPS obligations to targeted industries by 2030,[9] linking GECs to carbon-emission audits, and promoting international recognition of GECs.

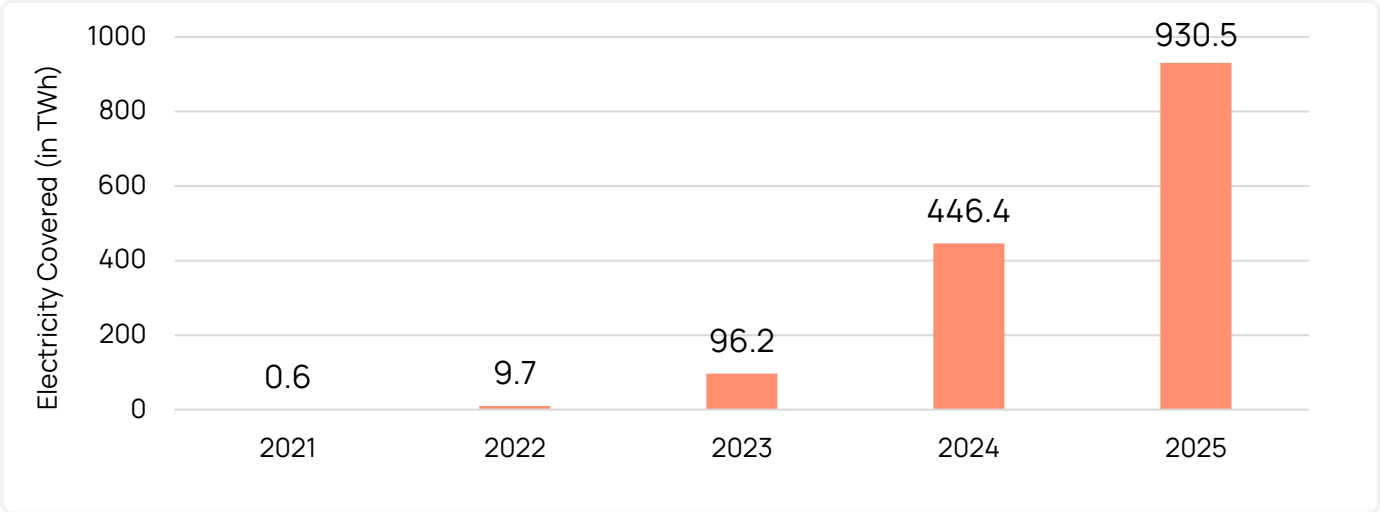
4. NDRC, National Bureau of Statistics & NEA, *Notice on Further Improving the Work Related to Excluding Newly Added Renewable Energy Consumption from Total Energy Consumption Control*, NDRC Operation [2022] No. 1258.
5. NDRC, Ministry of Finance & NEA, *Notice on Promoting Full Coverage of Renewable Energy GECs and Boosting Renewable Energy Consumption*, NDRC Energy [2023] No. 1044.
6. NEA, *Rules for the Issuance and Trading of Renewable Energy GECs*, NEA New Energy [2024] No. 67.
7. NEA & MEE, *Notice on Effectively Linking Renewable Energy GECs with the Voluntary Emission Reduction Market*, NEA New Energy [2024] No. 124.
8. NDRC et al., *Opinions on Facilitating High-Quality Development of the Renewable Energy GEC Market*, NDRC Energy [2025] No. 262.
9. Steel, non-ferrous metals, petrochemicals, construction materials, chemicals, and data centres.

3.1.3. GEC PRICING TRENDS

The GEC market underwent a dramatic transformation from 2021 to 2025, characterised by explosive growth in trading volume, alongside a sharp decline in prices. Trading volume surged from a mere 0.6 TWh in 2021 to 930.5 TWh in 2025, representing a compound annual growth rate of >500%.

This exponential expansion was driven by policy reforms that expanded the range of eligible renewable energy projects, growing corporate demand, and increased market liquidity. In contrast, the monthly average price trend shows a clear downward trajectory, reflecting a significant oversupply of certificates as issuance largely outpaced demand growth.

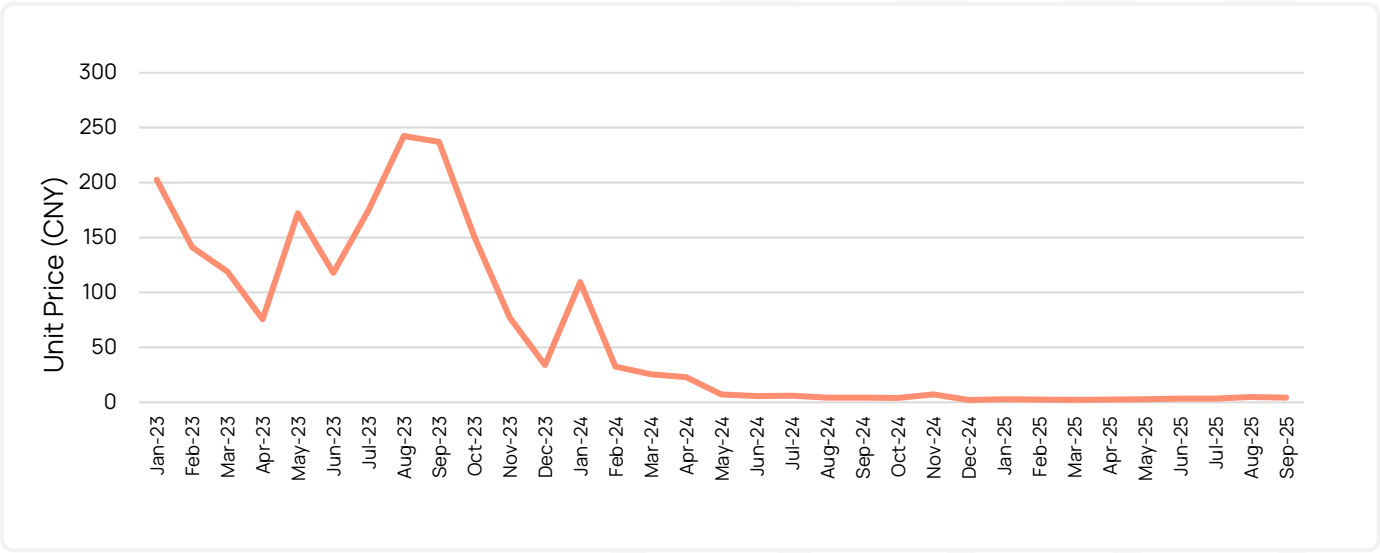
Figure 5: GEC Annual Trading Volumes 2021-2025



Source: NEA

This price collapse has critical implications. A certificate market priced near zero carries limited signalling value. It provides little incentive for buyers to differentiate renewable attributes by time, location, or additionality, and it limits developers' ability to monetise anything beyond "regular" MWh of renewable power. The decline in GEC prices has mirrored a broader compression of green power premiums as renewable generation costs and market prices have fallen, and as certificate supply expanded faster than demand. Later sections of this report discuss how supplementing GECs with more time-resolved approaches could, over time, enable differentiated value tiers within the GEC market.

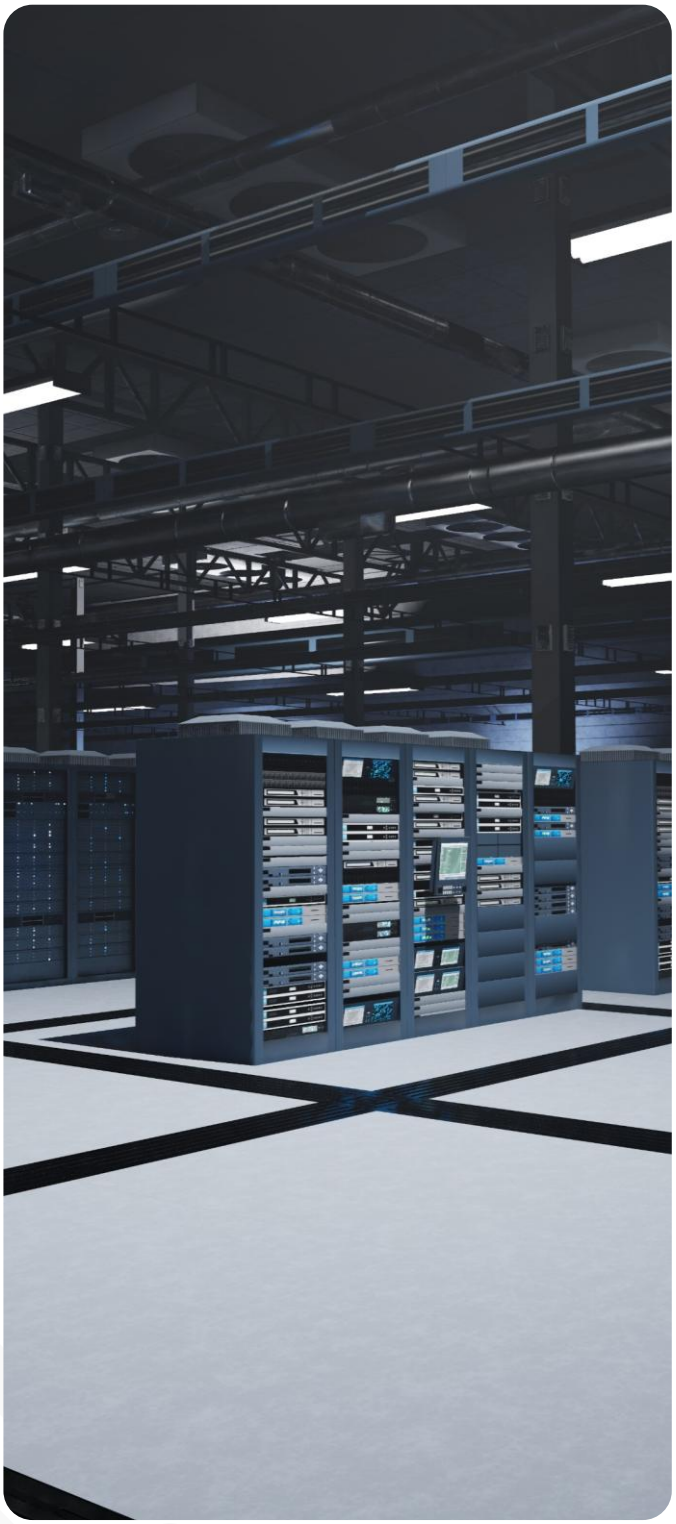
Figure 6: GEC Monthly Average Price 2023-2025



Source: NEA

3.1.4. ONGOING GEC REFINEMENT

The NEA's new trial rules document, formalised as Document 107 in January 2026 represents a critical refinement in the system's evolution.[10] By introducing mandatory cancellation of expired certificates and enforcing annual matching for consumption claims,[11] the 2026 rules address key operational gaps, transitioning the GEC system from establishing basic coverage and liquidity to enforcing temporal integrity and environmental attribute exclusivity. The newly added "foreign users" clause opens a window for cross-border green power consumption, laying groundwork for the future international recognition of Chinese GECs.



3.2. GEC RECOGNITION UNDER INTERNATIONAL VOLUNTARY STANDARDS

3.2.1. UNCONDITIONAL RECOGNITION FROM RE100

RE100's views on Chinese GECs trace a clear evolution from conditional acceptance to full, unconditional recognition, following sustained enhancements to the credibility of the GEC instrument itself. Initially, RE100's engagement with GECs was highly cautious and conditional. However, following the systemic policy reforms from 2023 to 2025 and sustained technical consultation between RE100 and Chinese institutions, Chinese GECs finally gained RE100's recognition. In a May 2025, release, RE100 announced the unconditional recognition of the reformed GEC system, stating the GEC now ensures renewables purchases have a "verifiable, real-world impact."[12] This enables an easier compliance path for RE100 member companies in China and secures renewable consumption recognition across global supply chains.

10. NEA, *Implementation Rules for the Management of Renewable Energy GECs (Trial)*, NEA Qualification Regulation [2025] No. 107.
11. After 1 January 2026, GECs used to make green electricity consumption claims must correspond to electricity generated in the same calendar year as the consumption. This moves beyond the previous two-year validity window and explicitly encourages stakeholders to improve temporal matching precision, signaling alignment with evolving international standards for granular accounting.
12. Climate Group, *China's Energy Market 'Open for Business' After Support from RE100 on Certificates*, 8 May 2025, https://www.theclimategroup.org/our-work/press/chinas-energy-market-open-business-after-support-re100-certificates

3.2.2. EVOLVING INTERNATIONAL STANDARDS: TOWARD TEMPORAL MATCHING

The trend in international corporate climate accounting is also moving toward stronger expectations on where and when clean electricity is sourced. SBTi's draft Corporate Net-Zero Standard Version 2 is one prominent example, introducing more stringent criteria for Scope 2 decarbonisation that include the use of credible contractual instruments and stronger geographic and temporal matching requirements, to be phased in starting with the largest electricity consumers.

In parallel, the Greenhouse Gas Protocol is conducting its Scope 2 update process, including proposals that would tighten eligibility and place greater emphasis on geographic and temporal alignment, while other reporting frameworks (including ISO 14064 1) are also evolving to raise scrutiny of electricity claims. These separate processes are not necessarily synchronised and final requirements will vary, but they collectively indicate rising expectations towards corporates for time-consistent evidence of renewable consumption.

While China's GECs are well positioned for annual matching under RE100 and current SBTi guidelines, they remain a monthly instrument and are not equipped for the emerging best practices around hourly (24/7) matching. Separately from formal standards, voluntary leadership initiatives such as The Climate Group's 24/7 CFE Coalition are reinforcing this trend by encouraging corporates to move toward round the clock carbon free energy. Taken together, these developments suggest that international acceptance of Chinese instruments will increasingly depend not only on attribute integrity (i.e., avoiding double counting), but also on the ability to link claims to time- and location-consistent evidence.

3.3. INTEGRATION OF GECS AND CHINA'S CARBON MARKET

China's carbon regulatory framework operates through two systems: the mandatory national Emission Trading System (ETS) covering more than 3,500 companies from the power, steel, cement, and aluminium smelting sectors; and the voluntary CCER scheme. Seven regional ETSs operate in parallel, established earlier and covering sectors and entities not yet included in the national system.

The national ETS does not regulate the indirect emissions (Scope 2) from purchased electricity for covered entities. The MEE's 2025 notice clarified that, at present, indirect emissions from electricity use by covered entities are not included in the quota management scope of the national ETS.[13] This differs from the practice of some local ETSs, which incorporate indirect emissions from electricity and allow their reduction through the use of green electricity.

GECs and CCERs serve different but complementary purposes:

- **GECs function as the primary instrument for renewable energy attribute tracking and consumption claims.** They certify the zero-carbon nature of the underlying electricity, allowing corporate buyers to reduce their Scope 2 emissions. While essential for regulatory mandates (e.g. the "dual control" system, Renewable Portfolio Standards) and voluntary initiatives (e.g., RE100, SBTi), GECs cannot be used for national ETS compliance. Their role is to directly promote renewable energy development and consumption.
- **CCERs operate within the voluntary carbon market as carbon offset credits.** They are designed to incentivise projects with high additionality - emission reduction activities that would not have occurred without the carbon finance incentive. Regulated entities under the national ETS can use CCERs to offset up to 5% of their annual carbon allowance obligations.

13. MEE, *Notice on Matters Related to the National Carbon Emissions Trading Market for 2025*, MEE Climate [2025] No. 140.

Prior to the establishment of a formal coordination mechanism, certain renewable projects were eligible for both GEC and CCER issuance, resulting in potential double counting of environmental attributes. This loophole was eliminated in August 2024 when the NEA and MEE jointly issued a "choose one" notice: during a two-year transition period starting October 2024, deep-sea offshore wind and solar thermal projects must choose between issuing GECs or applying for CCERs for the same generation. After the transition period, the linkage requirements will be adjusted based on the assessment of the voluntary emission reduction market and the operation of GECs. An information sharing mechanism has been established to ensure data authenticity and traceability.

The NEA's Document No. 107, released in January 2026[14] looks to solidify the linkage between GECs and the CCER market by mandating the cancellation of GECs for any generation period where a project successfully registers corresponding CCERs. Forward-looking provisions, such as requiring annual matching from 2026 and encouraging improved temporal precision, lay the groundwork for the GEC system to support more granular, future-ready carbon accounting and trade-related carbon footprint calculations.

3.4. SUPPLEMENTING GECS WITH GRANULAR MATCHING

China's monthly GECs are designed to support annual, volumetric accounting for domestic regulatory compliance and corporate reporting. They enable entities to fulfil RPS obligations, obtain exemptions from the "dual control" system, and serve as a key instrument for carbon footprint accounting. For corporate reporting, GECs enable buyers to make credible annual renewable consumption claims for ESG disclosures or for initiatives like RE100 and SBTi. However, due to their monthly aggregation design, GECs cannot support functions requiring hourly temporal granularity, for instance matching for 24/7 CFE claims. Consequently, they cannot enable precise, time-aligned carbon footprint accounting for specific production periods or individual product batches.

A traditional monthly instrument like a GEC can be integrated with an hourly instrument (Granular Certificate, or GC) through a conversion process using hourly meter data. The process retains the original monthly EAC as the foundational record of environmental attributes but combines it with hourly generation data from a specific clean energy asset. Practically speaking, this requires access to interval generation data for the generator(s) backing the EAC (at least hourly, and ideally aligned to settlement interval where available). This data must be combined with a reconciliation process that ensures the sum of hourly volumes equals the total EAC volume, along with a consistent treatment for any mismatches or remainders. It also requires an auditable linkage between the underlying EAC retirement and the issued time-stamped records to prevent double counting and allow third-party verification. This combination "upgrades" the aggregate certificate into a time-stamped record, enabling precise hourly matching between renewable generation and consumption without replacing existing registry infrastructure. This approach is consistent with "Configuration 3" in the EnergyTag Granular Certificate Scheme Standard, which specifies how granular certificates can be issued by layering time-stamped meter data onto an existing certificate framework.[15]

Supplementing Chinese GECs with granular certificates or timestamps can be an interim solution. This can bridge the gap between monthly certificate issuance and use cases that require higher temporal precision but remains a supplemental layer rather than an intrinsic feature of the GEC instrument. As China's spot markets continue to enable shorter dispatch and settlement intervals, the underlying metering and settlement data needed for more granular attribute tracking is being created as well. An evolution of the GEC framework toward hourly issuance and matching would improve alignment between market settlement, metering, and attribute tracking, and would provide a clearer accounting basis for integrating storage and other flexibility resources.

A practical example of this interim approach was demonstrated in August 2025, when AsiaREC (a Hong Kong based non profit) completed China's first hourly matched PPA pilot in Guangzhou, enabling verified hourly matching for 20.5% of Guangzhou Hualing Company's 4 GWh monthly consumption. The pilot illustrated how time-stamped meter data can be layered onto a foundational monthly certificate to support hourly matching (i.e., EnergyTag's Configuration 3-style approach), while retaining the base role of the national GEC. For further examples of provincial-scale implementation (Jiangxi, Jiangsu), see Chapter 6.

14. NEA, *Implementation Rules for the Management of Renewable Energy GECs (Trial)*, NEA Qualification Regulation [2025] No. 107.
15. EnergyTag, *Granular Certificate Scheme Standard Version 2*, March 2024, https://energytag.org/wp-content/uploads/2024/12/EnergyTag_Granular-Certificate-Scheme-Standard-V2.pdf

04.

ENERGY STORAGE IN CHINA

Energy storage is becoming a central enabling technology for China's next phase of renewable integration, as rising solar and wind penetration increases the value of flexibility and shifting electricity across hours. This section summarises how storage is developing in China and explains why its economics and treatment in market and accounting rules matter for granular matching and, ultimately, RTC clean power claims.

4.1. CURRENT POLICY AND MARKET LANDSCAPE

4.1.1. WHY STORAGE MATTERS IN CHINA

China's rapid growth in wind and solar has increased the system value of flexibility by widening mismatches between electricity demand and variable supply. In provinces with rising solar penetration, daytime oversupply and evening ramp needs increasingly produce "duck curve" dynamics, with weak or even negative prices at midday and scarcity pricing during evening peaks. Flexible storage can arbitrage these price spreads by charging during low-price hours and discharging during higher-value periods, while also providing system services like congestion mitigation, curtailment risk reduction, and dispatch stabilisation. However, these incentives only translate into investable projects if storage operators are allowed to participate in wholesale markets and to stack revenues across energy, ancillary services, and capacity compensation.

4.1.2. SCALE AND STRUCTURE OF CHINA'S STORAGE BUILDOUT

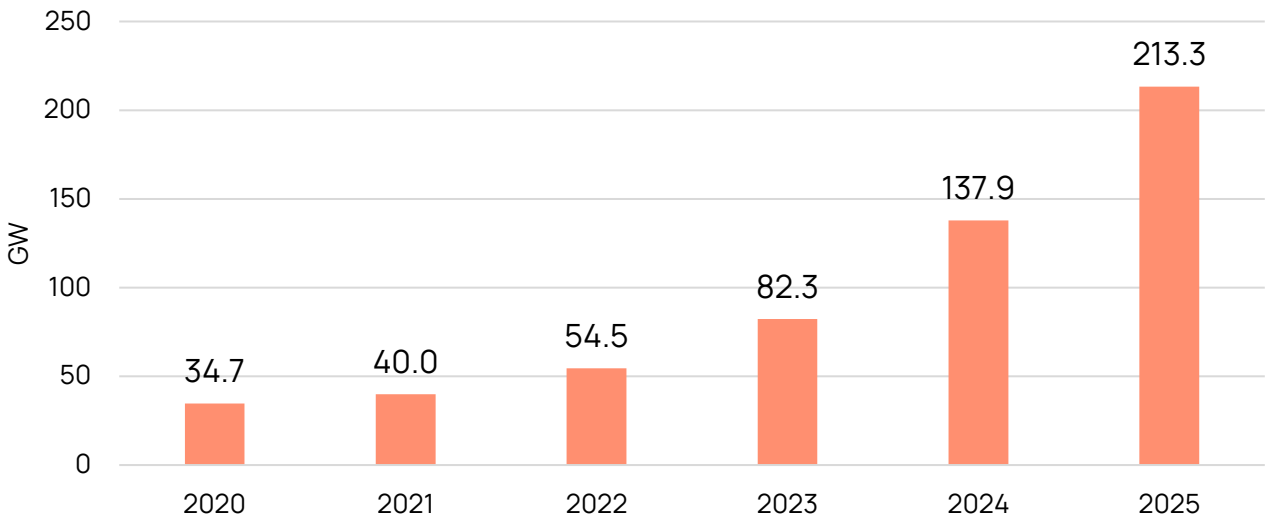
By the end of 2025, China's operating storage fleet exceeded 213 GW, with "new-type energy storage" (i.e., storage excluding pumped-hydro) comprising the bulk of incremental additions. Of these "new-type" storage additions, electrochemical (battery) solutions were dominant, with 96% of all new-type energy storage in the country being lithium-ion battery energy storage systems (BESS).

Deployment is geographically concentrated in renewable-heavy provinces and major load centres, reflecting the two primary use cases.

1. Renewable integration and transmission support for export-oriented regions, and
2. Grid-support and balancing services in demand centres.

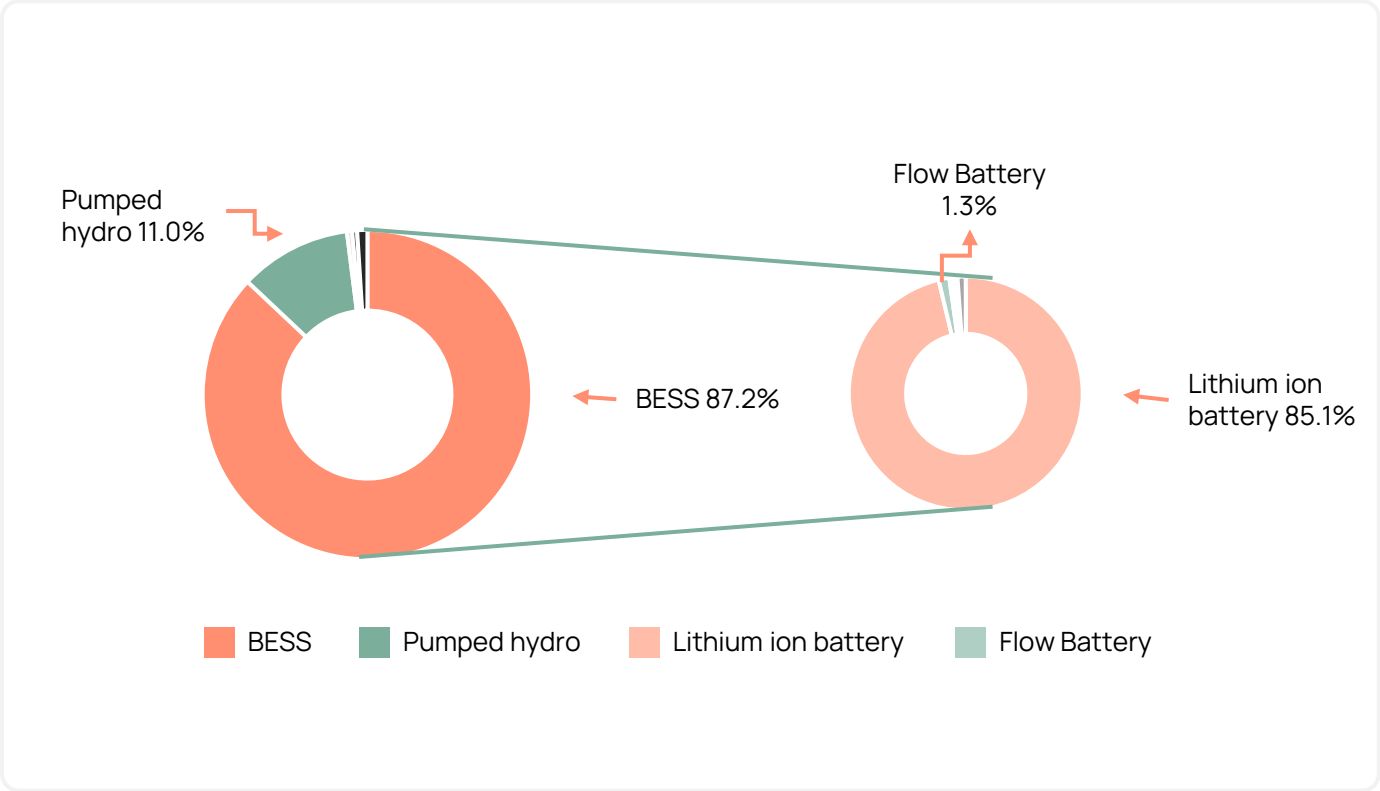
While these deployment patterns are well understood, the key constraint on the sustainable scale-up of the storage sector is increasingly commercial rather than technical, especially the durability and predictability of revenue under expanding spot markets and constantly evolving tariff structures

Figure 7: China's storage capacity 2020 – 2025



Source: NDRC, NEA, China New Energy Storage Association

Figure 8: Installed Energy Storage Capacity by Technology Type in 2025



Source: China New Energy Storage Association

4.1.3. POLICY SHIFT FROM MANDATORY MATCHING TO MARKET-BASED INTEGRATION

China's storage promotion policy has begun shifting away from administratively mandated capacity matching toward market-based integration. A key inflection point was 2025's Document No. 136, which is most associated with pushing renewables further into market-based trading, but also contained an important notice to provincial governments that mandatory storage matching could no longer be treated as a prerequisite for renewable project approval. This shift helped re-orient storage investment toward system value rather than compliance volume, but it also removed a major legacy revenue channel for independent storage: capacity leasing or "capacity rental" arrangements tied to renewable project requirements.

In the near term, this transition will reduce the financial feasibility of independent storage, particularly because spot power price spreads are often still shallow (in provinces where such information is publicly available at all), ancillary service markets are still developing, and capacity compensation is highly province-dependent and limited in scope.

These capacity mechanisms are not competitive "capacity markets" and the policy design has, to date, primarily targeted coal (and in some cases gas and pumped hydro) as recipients, with grid-side battery storage only added more recently, so in practice most capacity payments still accrue to thermal fleets. In other words, policy is pushing storage toward market-based value, but the current market design is not necessarily sophisticated enough to provide the revenue stack needed to support that value.

In recent years, national and provincial action plans have increasingly emphasised "revenue stacking" (arbitrage + ancillary services + capacity/long-term service contracts), suggesting that the central challenge is not whether storage is needed, but whether market rules will effectively value and monetise the services storage provides (and allow those price signals to be public and transparent).

Table 3: Storage Policy Evolution from Policy-Driven to Market-Driven Roadmap

Stage/Document	Description/Content
Prior to 2024: Rising storage mandates & marketisation initiation	10-30% mandatory storage ratios for RE projects, but by 2023 the average utilisation rate was only 17%, revealing the inefficiency of rigid quota-based storage co-location rules.
	2024-2025 Energy-Saving & Decarbonisation Action Plan relaxed required utilisation rate of renewables to 90% in some resource-rich regions, indirectly lower mandatory storage requirements.
Feb 2025: The landmark *"Doc No. 136"*	Energy storage co-location **should no longer be considered a prerequisite** for clean energy projects.
Sep 2025: Special Action for Scaled Deployment of New-Type Energy Storage (2025-2027)	Targets new-type energy storage full commercialisation, with market mechanisms largely established and large-scale deployment in 2025-2027.
Nov 12, 2025: Guiding Opinions on Promoting Integrated RE Development	By 2030 integrated, co-located, and hybridised RE projects will become the central pillar of RE expansion, providing an institutional foundation for coordinated growth of storage with clean energy.

Source: NDRC, NEA

4.1.4. IMPLICATIONS OF STORAGE FOR GRANULAR CLEAN ENERGY MATCHING

For the purposes of this report, storage is analytically important because its value is inherently time-dependent: it shifts energy from hours of surplus (and low prices) into hours of scarcity (and higher system value), while also providing flexibility services that are activated under specific operating conditions. As a result, the contribution of storage to renewable integration and system reliability depends not only on installed capacity, but on when and where storage charges and discharges, and which hours it mitigates congestion, curtailment risk, or ramping needs.

This provides the bridge to granular accounting. If renewable attributes are tracked only on an annual or monthly basis, the time dimension that storage is designed to address is largely obscured in procurement and reporting. By contrast, hourly tracking of green attributes can make the timing of renewable supply and storage-enabled delivery observable to buyers and intermediaries. In turn, this supports procurement structures and operational incentives that preferentially absorb renewable output during oversupplied hours and reduce stress during peak hours. In this way, granular accounting complements market design by aligning clean-energy claims and contracting frameworks more closely with the temporal realities that drive storage value.

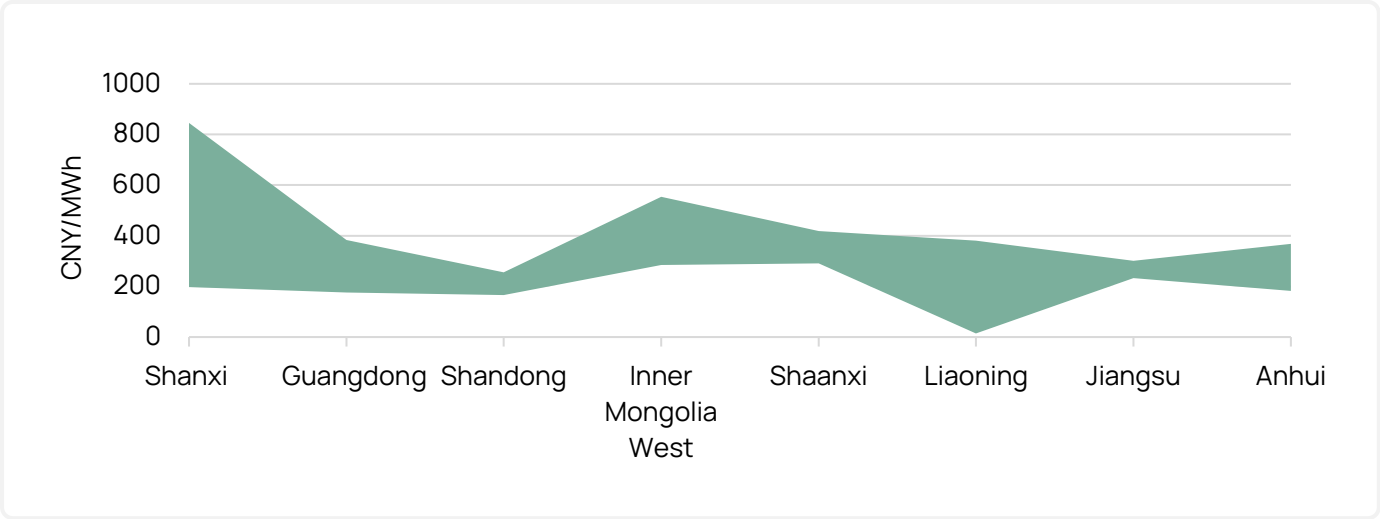
4.2. STORAGE MARKET DESIGN AND REVENUE MECHANISMS

Denied capacity leasing revenues following the implementation of Document No. 136, storage operators must now solve the "missing money" problem via a revenue stack of energy arbitrage, ancillary services, and capacity payments:

4.2.1. ENERGY ARBITRAGE

Energy arbitrage is the simplest storage business model: charge during low-price hours and discharge during high-price hours. In China's spot markets, the price patterns that create attractive opportunities for energy arbitrage are beginning to emerge - solar-driven price weakness at midday followed by peak pricing in the evenings. Periodic negative pricing in some markets underlines this trend even more. However, price arbitrage is currently rarely sufficient to drive the storage investment case on its own.

Figure 9: Spot Price Spread of Selected Provinces 2025/12/29 - 2026/01/04



Source: Provincial EA, Provincial power exchanges

The first and most obvious limit for the relevance of price arbitrage in driving storage growth is that China's spot markets are still immature and emergent across most of the country in 2026, limiting depth and frequency of historical market data. Second, pricing collars (floors or ceilings) and administrative interventions can limit the realised price spread at exactly the periods that would otherwise monetise flexibility. Third, storage dispatch is often constrained by technical requirements, grid security reviews, and coordination with dispatch organisations, which limits the ability of the storage operator to effectively respond to price signals. Finally, would-be storage operators must consider a certain cannibalisation risk: if price spreads remain attractively wide for extended periods of time, the resulting burst of newly constructed storage could potentially manifest as overbuilding, serving to compress the price delta that made the arbitrage opportunity attractive in the first place, leaving all storage operators out of the money. For all these reasons, arbitrage can be treated as a base revenue stream that improves with market maturity, but not as a standalone bankability anchor in most provinces today.

This cannibalisation risk will be familiar to observers of power markets in e.g. the UK and Texas, where spreads are now also being squeezed. This ultimately increases the relevance of long-term contracts for storage markets or hybrid PPAs.

4.2.2. Ancillary Services

For short-duration storage (especially lithium-ion), ancillary services, particularly frequency regulation and related load-following/balancing products, often provide the clearest near-term pathway to monetisation because they reward fast response and high controllability. In provinces where ancillary markets are functional and open to storage participation, they can provide a material share of revenues.

The limiting factors are largely market-design related, including the eligibility and qualification rules for storage participation, rules regarding performance measurement and penalties, and whether settlement prices are market-cleared or administratively set. When these items are stable and transparent, storage can compete on performance; where they are uncertain or capped, ancillary services provide only supplemental income and cannot resolve the "missing money" problem.

4.2.3. Capacity Compensation

Following policy reform at the start of 2026, another new potential revenue source for independent storage has been established: a stable capacity-style payment that recognises storage's contribution to adequacy and peak support. While this is being rolled out across some provinces, it is not yet widespread or well developed.

Capacity payments are a recognition that storage delivers systemic value even when arbitrage spreads are weak and even when ancillary procurement volumes are limited. Where a capacity payment or long-term availability contract exists, it can serve as a revenue floor that improves bankability and reduces reliance on volatile spot spreads. Where it does not exist, storage faces an "unfair" structural dilemma: it is expected to provide long-term reliability value but must recover costs primarily through short-term price volatility. This mismatch becomes more obvious as policies reduce mandatory co-location (eroding capacity leasing revenues) and push storage toward "standalone" economics. In the future, renewables + storage PPAs could help overcome this challenge. Storage can only truly be considered a flexibility resource when it is compensated appropriately for the flexibility it provides.

4.2.4. THE ROLE OF STORAGE RETAILERS AND AGGREGATORS

In China's electricity markets, independent and user-side storage is rarely monetised through simple bilateral arrangements. Instead, storage is commonly integrated into broader portfolios managed by power retailers, aggregators, or virtual power plant (VPP) platforms. This reflects both the structure of market access rules and the evolving nature of storage revenue streams. Arbitrage opportunities based on administratively defined peak/valley spreads are disappearing, while participation in ancillary services markets or wholesale market trading requires operational coordination and compliance capabilities that many individual storage owners do not possess.

In this context, retailers and aggregators can play a practical role in consolidating scale, interfacing with market platforms, and managing settlement and compliance requirements. Rather than storage value being monetised directly through a single, transparent price signal, it can be realised via portfolio-level amalgamation and execution.

4.3. GRANULAR MATCHING AND THE VALUE OF STORAGE

This section considers storage not only as a physical flexibility resource, but also in terms of how its time-shifting capacity can be recognised in time matched clean power procurement and reporting frameworks. The discussion below focuses on why non granular approaches tend to under-value storage and how more time-resolved matching can change the basis on which storage-enabled delivery is monetised.

4.3.1. CURRENT ACCOUNTING FRAMEWORKS UNDER-VALUE STORAGE

Energy storage derives its system value primarily from shifting electricity across time. In power systems with rising shares of variable renewables, this temporal function becomes increasingly important for reducing curtailment, mitigating oversupply, and supporting reliable renewable integration. However, the existing renewable consumption compliance frameworks in China treat renewable attributes as fully fungible within an annual or monthly period. As a result, the time-shifting dimension that storage is designed to address – and is fully capable of addressing – is largely invisible in reporting and contracting frameworks.

This temporal mismatch has practical consequences for how storage interacts with renewable procurement. In China, "green storage" does not carry an independent green attribute and therefore currently cannot be monetised through certificates or green premiums. As a result, the storage value of green power can only be captured indirectly, via improved temporal generation curves, avoidance of deviation penalties, or reduction of risk, rather than through explicit pricing of stored green electrons. For corporate buyers, this means green claims continue to rest on non-granular generation and certificates.

4.3.2. GRANULAR MATCHING REGIMES HELP STORAGE CAPTURE MORE VALUE

The commercial logic is that hourly matching can create a differentiated clean electricity product. A buyer seeking time matched coverage places greater value on clean delivery in "hard to supply" hours, when renewable output is scarce (or when system conditions make clean delivery more difficult). Storage can capture that value by shifting renewable output from oversupplied hours into scarcer hours.

In this sense, granular matching creates a mechanism for the market to explicitly value temporal green power products. This is especially important because annual matching provides little incentive for storage or other firming solutions: it treats renewable generation in "easy" hours as equivalent to clean supply in "hard-to-supply" hours. By differentiating value across time, granular matching can create stronger incentives for storage and other firming solutions that shift renewable output from periods of surplus to periods of scarcity.

While granular matching alone is not sufficient to fully reduce curtailment risk or transform storage economics at scale, it is a necessary step in enabling these outcomes. This is particularly relevant in a system where the current volumetric approaches provide limited incentives for flexibility and time-shifting. To be sure, comprehensively realising the value implied by hourly signals still depends heavily on complementary market and system conditions. These include market access and operational rules that allow storage to charge/discharge and capture spreads, settlement and dispatch practices that permit time-shifting at meaningful scale, adequate transmission availability and transparency, and procurement structures or flexible demand that can respond to hourly signals. If these enabling conditions are partial or uneven, time-resolved attributes may improve the robustness of claims and improve price signals, but they will not automatically overcome the operational and commercial constraints that limit storage value capture currently.

4.3.3. RTC CLEAN POWER AND END-USER STORAGE SOLUTIONS

Most discussions of 24/7 clean power implicitly assume generator-side firming, whereby renewable producers (or aggregating retailers) pair generation with storage or portfolios of generation assets to deliver a time-matched product to buyers. This is a sensible way to approach the topic when the most pressing system-level challenge is intra-day imbalances between renewable supply and demand. However, storage also enables an alternative pathway for granular matching: **buyer-side temporal balancing.** Under this model, an end-user can contract to deliberately over-procure renewable electricity during oversupplied hours, charge behind-the-meter storage, and discharge that energy during periods when clean power is scarce, thereby achieving round-the-clock clean consumption without relying on generators to offer a firmed product

This approach shifts the storage assets from supply-side integration tools to demand-side compliance instruments. While it raises additional measurement and verification challenges, it highlights how granular accounting does not mandate who must provide flexibility or create a temporal solution in and of itself. Instead, it incentivises the pursuit of flexibility, whether provided by generators, retailers, or consumers themselves.

In China, buyer side behind the meter (BTM) storage to arbitrage green power is still theoretical, but increasingly feasible under evolving market conditions. Large commercial users like data centres and industrial parks combine relatively inflexible 24/7 loads with growing exposure to time differentiated price signals and growing incentives for green procurement.

Whether buyer-side BTM storage can scale, however, depends less on engineering feasibility than on institutional design. On the positive side, broader spot market development and the gradual weakening of administratively fixed retail time of use structures could strengthen incentives for buyers to charge storage during low price, renewable surplus hours and discharge later. On the constraining side, storage still cannot create an independent renewable attribute. Without explicit rules for verifying that storage charging was sourced from clean electricity in a given hour, and mechanisms for tracking losses, and preventing double counting, buyer side firming may remain a private optimisation option rather than a scalable, recognised compliance pathway. In addition, China's centralised dispatch and provincial governance structures may favour generator or retailer mediated firming approaches before endorsing widespread end user managed 24/7 strategies.

05.

INDUSTRY-SIDE DRIVERS FOR GRANULAR MATCHING

By 2021, grid-parity Feed-in-Tariffs became the standard compensation mechanism for China's newbuild wind and solar projects, replacing the subsidy scheme (which continued to be paid out to older projects). Under the grid-parity FiT scheme, wind and solar generators received dispatch compensation equal to the local coal-fired base price, with no additional subsidy component. Early policy indicated grid-parity projects would be eligible for 20-year offtake agreements, although this was later revised. Although dispatch was guaranteed, the annual offtake volumes were not unlimited. "Annualized reasonable utilization hours" were introduced which capped the hours eligible for guaranteed grid-parity compensation. Any generation beyond these contracted volumes could be sold in the emerging power markets.

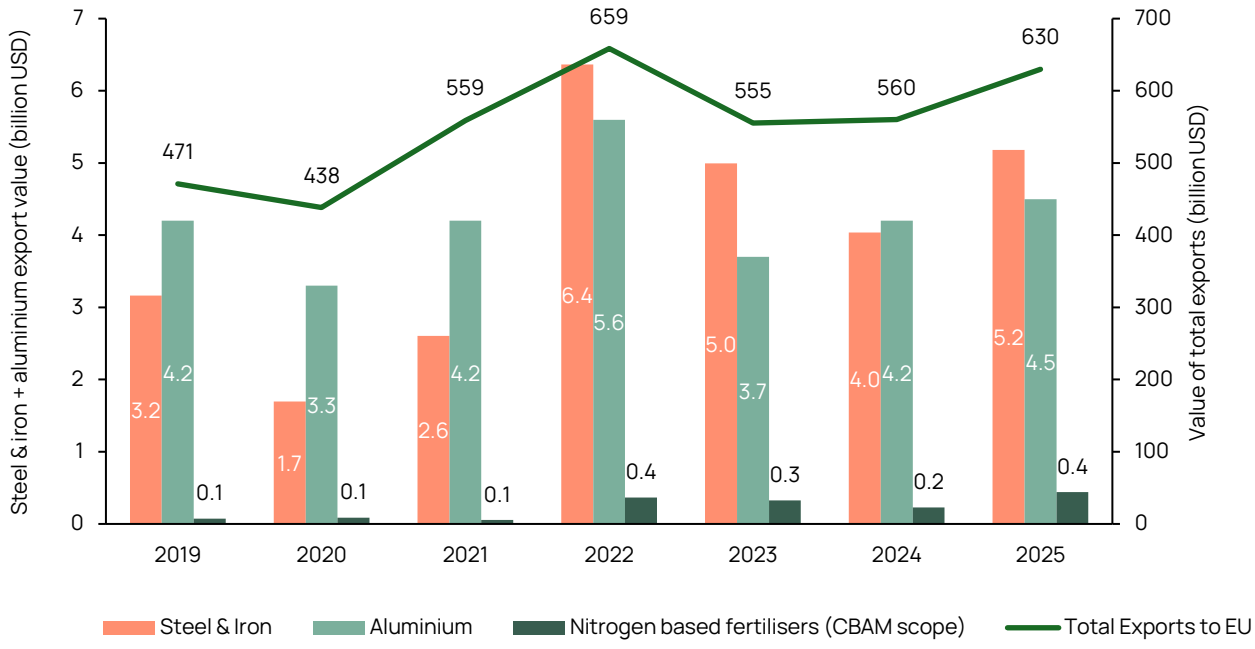
5.1. CHINA'S EXPOSURE TO CBAM IS MODEST BUT RISING

The EU's Carbon Border Adjustment Mechanism (CBAM) officially came into effect on 1 January 2026. CBAM imposes a carbon price on embedded emissions in carbon-intensive imports, with intent to prevent carbon leakage, aligning carbon costs between EU and non-EU producers. CBAM currently applies to six sectors: iron and steel, aluminum, cement, fertilizers, electricity, and hydrogen. Cement, fertilizers and electricity face charges on both direct and indirect emissions, while steel, aluminum and hydrogen are so far exempt from indirect emissions charges, likely until 2030.[16]

Although China is among the top exporters of CBAM-implicated goods to the EU, its overall exposure is still limited in the context of its overall exports. Among the six major sectors covered currently, only three saw substantial trade activity with the EU in 2025. Steel and iron[17] accounted for 0.8% of Chinese exports by value to the EU in 2025, while aluminum accounted for 0.7% and nitrogen fertilizers just 0.1% for a total of 1.6%.

In 2025, the EU ETS price averaged EUR 74 (~USD 84) per tonne, while China's carbon price hovered around just CNY 71 (~USD 10), meaning engaging in domestic carbon trading will be insufficient to mitigate CBAM exposure.

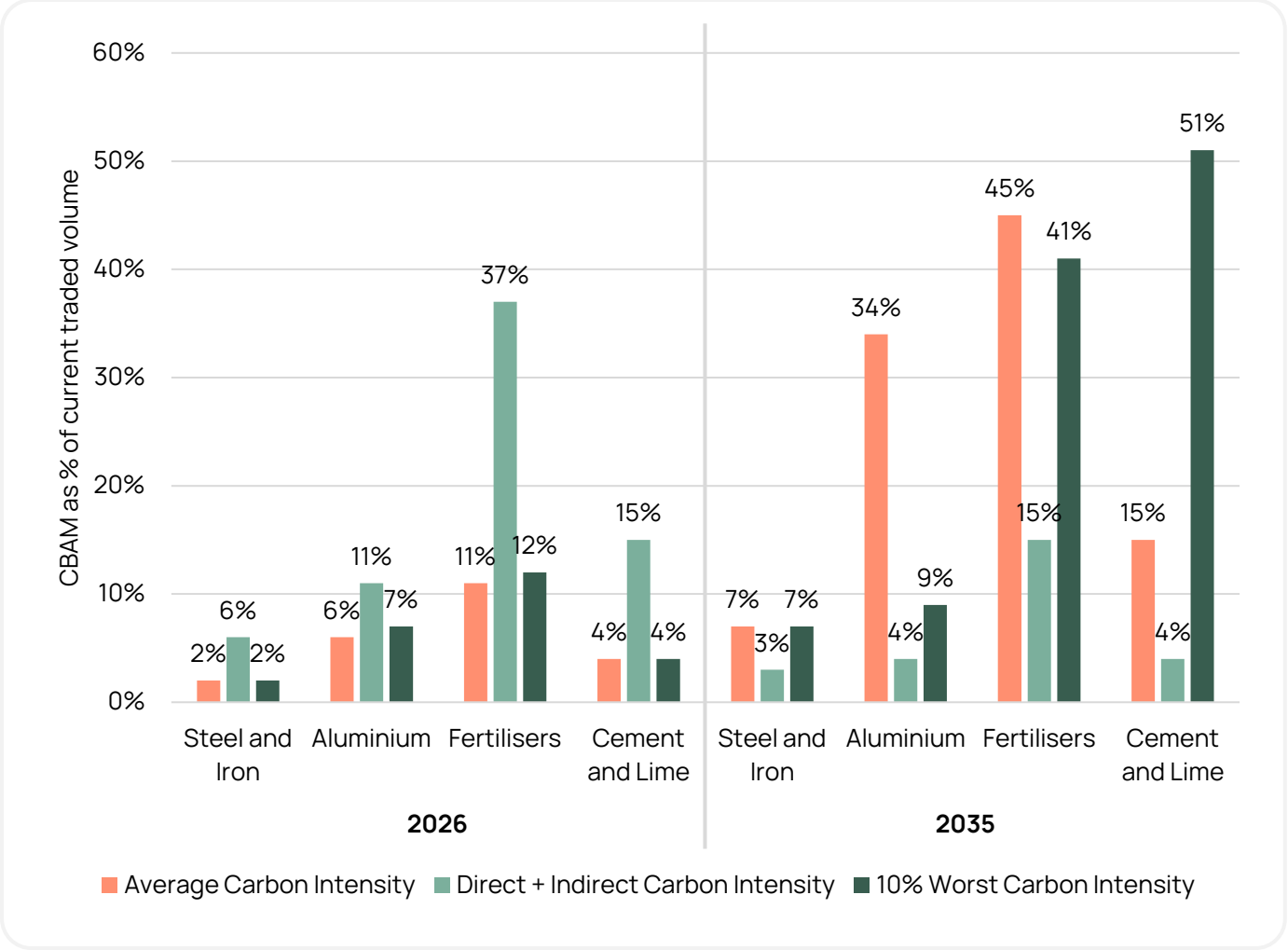
Figure 10: Chinese CBAM-Exposed Exports vs. Total Exports to the EU 2019-2025



Source: UN Comtrade

16. CBAM exempts steel, aluminum, and hydrogen from indirect emissions charges, mirroring the indirect cost compensation that EU domestic producers receive under the ETS State Aid Guidelines (2021-2030).
17. In the UN customs trade database, this includes HS 72 and portions of HS 73 (namely 7301 and 7303-06).

Figure 11: CBAM Fees by Sector 2026 vs 2035



Source: Sandbag

Looking ahead, CBAM is expected to expand to all sectors under the EU ETS by 2030. Chinese exporters will soon face carbon border taxes on nearly all goods exported to the EU, and those that can demonstrate low-carbon production (including green electricity use) will enjoy apparent advantages.

In December 2025, the EU announced plans from 2028 to expand CBAM to cover 180 steel- and aluminum- intensive downstream products, including machinery, vehicle components and household appliances. In contrast to primary materials, manufactured goods account for almost 97% of Chinese exports to the EU, led by machinery and vehicles.[18] Under this proposed expansion, Chinese exports would be highly exposed and embedded emissions tracking would become considerably more complex, especially for products with long and fragmented supply chains. These carbon border charges are expected to be material and will pose a considerable cost compliance burden.

18. European Commission, *EU trade relations with China: facts, figures and latest developments,* https://policy.trade.ec.europa.eu/eu-trade-relationships-country-and-region/countries-and-regions/china_en

5.2. CBAM COMPLIANCE IS BECOMING MORE COMPLEX

5.2.1. CBAM COMPLIANCE NOW MANDATES HOURLY MATCHING

According to the CBAM implementation rules released in December 2025 (Commission Implementing Regulation (EU) 2025/2547 of 10 December 2025)[19] importers seeking to use their actual market-based emissions data for calculating indirect electricity emissions (rather than defaulting to the location-based average) must now prove the use of physically deliverable, hourly-matched clean electricity for consumption.

Section D.2.4. of the implementing rules set out two qualifying pathways to apply actual emission values over default: a direct physical link between the power generator and the production facility, or a qualifying PPA signed directly between both parties. Qualifying PPAs require: the original contract signed directly with the generator; smart metering data proving generation and equivalent delivery occurring within the same hourly measurement period; and documentation from transmission system operators confirming a physical grid connection. If an intermediary is involved, the generator, intermediary and customer must sign a single tripartite contract.

Under these requirements, Chinese exporters face several challenges. China's prevailing retail power procurement model featuring decoupled contracts between generators-retailers and retailers-consumers is not time-matched. Retailer-consumer contracts are settled monthly and thus do not meet CBAM's definition of a qualifying green PPA.[20] Additionally, their monthly or annual settlement cycles lack the hourly metering data required to prove real-time generation-consumption alignment. Furthermore, Chinese unbundled instruments are not recognized by CBAM, as they do not impose an obligation for physical delivery (this applies to all unbundled certificates, not just GECs). Only producers that can source physically delivered, hourly-matched clean electricity will be able to reduce their CBAM exposure via compliance actions in China, enhancing their competitiveness in the EU market.

5.2.2. CBAM'S IMPLICATIONS FOR CHINESE POWER MARKET DESIGN

CBAM's final compliance rulesets shift electricity from a background assumption to a traceable, time-stamped, verifiable production input for trade-related emissions accounting and industrial competitiveness. For Chinese energy policymakers and export-exposed industrial producers alike, this has profound implications:

- Electricity becomes a verifiable production input. Electricity can no longer be treated as a generic commodity. Its consumption details, including specific carbon content, must now be traced, verified, and even timestamped. This directly determines Chinese export compliance and competitiveness for CBAM-covered goods and their downstream products, both in the EU and in an increasingly carbon-constrained world.
- A shift to physical, hourly-matched green power delivery is indicated. CBAM explicitly rejects unbundled, non-time-matched EACs (including GECs) and mandates that green power consumption must align with actual production hours. This places severe strain on China's traditional green power trading model – which has long relied on annual settlement and separate power-certificate transactions. This change will force a full shift to physical source-load direct connection, full-chain traceability, and hourly-level trading and settlement to maintain compliance.

19. Commission Implementing Regulation (EU) 2025/2547 (EUR-Lex).
20. As a nomenclature clarification, it is common industry convention in China to call green retail power supply agreements "Green PPAs". However, these are best understood as what would be called "green tariffs" in Europe, typically signed for short tenors and pre-existing assets. Long-term agreements for green power supply signed prior to the construction of the renewable asset (i.e. "true green PPAs") are still relatively rare.

- Accelerated national unified power market. To access lower-emission power, export-oriented industries in coastal provinces must secure scarce local supply or sign PPAs with generators in China's northwest renewable bases. This creates sustained commercial demand for green power and reinforces China's policy-driven national unified power market agenda, providing momentum to dismantle cross-provincial trade barriers, standardize trading rules, open interregional transmission markets and optimize nationwide renewable allocation. System stress intensifies as high-penetration renewable integration and expanded cross-provincial transmission impose greater demands on grid security, dispatch coordination, and ancillary services. This requires parallel investments in flexibility resources and market mechanisms to maintain reliability while expanding green power access for exporters.
- Power market infrastructure (both physical and commercial) repurposed for trade compliance. The capability to provide hourly-matched, physically delivered low-carbon electricity with third-party verification is no longer an optional upgrade – it is now a trade enabler and market access requirement. To meet CBAM's rigorous monitoring, reporting and verification (MRV) standards, China has rapidly advanced its carbon footprint accounting framework alongside tightened supervision and accreditation of third-party verifiers. These revisions transform power market infrastructure from a purely operational system into a trade-aligned carbon data governance platform, ensuring that exported goods can be backed by credible, traceable emissions evidence.

- Enhanced domestic carbon market and deeper power-carbon linkage. With embedded emissions priced at the EU border, a robust domestic carbon price enables exporters to remain competitive, allows state actors to retain revenues, and accelerates domestic decarbonization. China's national ETS expansion to steel, aluminum, and cement is already a move in this direction. This trajectory further requires power market design to strengthen carbon cost transmission mechanisms across the supply chain and foster integrated power-carbon market operation – where green power is explicitly recognized in carbon compliance and carbon costs are transparently embedded in electricity pricing. Crucially, this integration must be carefully calibrated to prevent the internalization of carbon costs from driving up overall electricity prices and damaging industrial competitiveness.
- In the near term, CBAM acts as a cost-adder for China's export-oriented industries, exposing institutional lags in the existing power market design that misalign with EU requirements. In the long term, however, CBAM functions as an external catalyst that aligns with and reinforces China's domestic power market reform trajectory. It drives the development of a low-carbon, flexible power system aligned with international standards, advancing China's energy transition while securing its industrial competitiveness and lending it a stronger voice in global carbon rule-setting.

5.3. GREEN HYDROGEN CLAIMS REQUIRE HOURLY TRACKING

In 2023, the EU published its rules for green hydrogen under the Renewable Fuels of Non-Biological Origin (RFNBO) framework. From 2030 onward, hydrogen and its derivatives – whether produced in the EU or imported from abroad – must meet an hourly matching requirement between renewable electricity generation and electrolyze power consumption to qualify as green. As with CBAM, the long lead time between announcement and enforcement gives exposed producers ample time to prepare and adapt.

The RFNBO rules impose temporal and geographic matching (and, over time, additionality) conditions on the renewable electricity used to power electrolysis. In practice, meeting these requirements will require granular, time stamped tracking and an auditable evidence chain linking renewable generation to electrolyze consumption.

While the legislation does not, by itself, mandate a specific "certificate" instrument, compliance will likely be operationalized through recognized certification schemes and supporting documentation. This is directly relevant for exporters of green hydrogen (or green hydrogen derivatives) across APAC, where most major regional markets have already formally established their national hydrogen strategies and are anticipating selling into EU markets, making the practical availability of hourly, auditable electricity evidence a near-term competitiveness issue.

China provides a good illustration of this issue. Domestically, green hydrogen policy is being integrated into the existing renewable portfolio standard (RPS) framework, with green hydrogen and its derivatives on the path to being treated as compliance-eligible forms of green consumption. Initial implementation of this framework began in 2025, with policy documents indicating selected industrial users would soon be required to meet minimum quotas for green hydrogen or derivatives in their primary energy consumption mix. A dedicated certification system for green hydrogen will be necessary to enable such a quota-based system but is still in its early stages and will need to undergo extensive pilots first, potentially beginning in late 2026.

At present, China's hydrogen production remains overwhelmingly fossil fuel-based, produced via coal, gas or as an industrial by-product, much the same as hydrogen is produced elsewhere in the world. Since the announcement of China's "dual carbon" goals in 2020, local governments have increasingly prioritized green hydrogen in their 14th FYPs and set production targets for green hydrogen. By the end of 2024, more than 600 green hydrogen projects had been announced nationwide. Northern and northwestern China accounted for nearly 90% of this capacity, reflecting both strong traditional industrial bases and rich renewable resources. In April 2025, the NDRC included nine green hydrogen projects in a list of advanced green and low-carbon technology demonstration projects,[21] which will receive targeted government investment support. The projects are primarily located in Inner Mongolia, Ningxia, Jiangsu, Tianjin, and Xinjiang.

In China, current and near-term demand for green hydrogen is focused on industrial feedstock substitution, especially as feedstocks for oil refining or ammonia/methanol synthesis. In these applications, green hydrogen can directly substitute for fossil-based hydrogen with minimal process changes, albeit at a considerable cost premium.

Meanwhile transport, metallurgy, power generation, heating, and energy storage applications remain largely pilot scale or experimental. China's direct hydrogen exports to the EU are currently negligible, so the nature of future RFNBO exposure is determined more by whether industrial feedstock oriented green hydrogen production will be able to meet EU green power matching requirements.

21. NDRC, *Notice on Issuing the List of Green and Low-Carbon Advanced Technology Demonstration Projects (Second Batch),* NDRC General Office [2025] No. 396.

06.

IMPLEMENTING GRANULAR MATCHING AND ROUND-THE-CLOCK CLEAN POWER MARKETS IN CHINA

This section focuses on the practical conditions under which granular matching and RTC-oriented clean power could move from pilots to repeatable procurement in China. For the purposes of this report, "success" is defined as the ability to make time-resolved clean electricity claims using auditable data and clear rules, and to implement those claims through workable market and contracting arrangements (recognizing that progress will likely emerge first in specific provinces and use cases). The discussion therefore examines in turn the key enabling features including market price and settlement signals, physical shifting capability, tracking and verification systems, and policy coordination, before shifting to examining how these elements fit within China's broader market maturation and what phased implementation could look like.

6.1. STATUS OF ROUND-THE-CLOCK CLEAN POWER IN CHINA

The sections that follow summaries where China currently stands across the four enabling layers most relevant to RTC-oriented clean power: short-term market price and settlement signals, physical shifting capacity, time-resolved tracking and verification, and policy coordination. Progress is uneven across provinces, so readiness is best understood as progress on different constituent building blocks, rather than a single unified progress bar.

6.1.1. MARKET MECHANISMS: REAL-TIME PRICE SIGNALS

The key market mechanism necessary for enabling time-resolved procurement and granular accounting is a clear time-limited price signal from a short-term power market visible to both power buyers and sellers. Today, China's power market mechanisms are maturing rapidly but unevenly. 2025 witnessed considerable progress, with several provincial spot market pilots achieving continuous 15-minute dispatch intervals and one province (Shanxi) becoming the first region to implement 5-minute settlement.

As of Q1 2026, seven provincial spot markets have now entered the formal operations phase. Although their role in price formation is expected to expand as markets mature, real time markets are still primarily used as dispatch and balancing tools rather than as tradable settlement platforms, and wholesale price formation is still constrained by administrative price caps and legacy coal benchmark anchoring. Most provinces remain in the trial operations phase of their spot power market development.

Document No. 1656[22] came into effect on 1 March 2026, signaling the phase-out of regulated time-of-use (ToU) tariffs for market participants in China. Provincial implementation of this mandate is proceeding accordingly. For grid-delegate power buyers, regulated ToU tariffs remain. The market's ability to send efficient temporal signals for green electricity value is constrained. This is because the green premium is subject to an administratively determined price collar and fixed for all of the 24 hours of the day. Consequently, there is no price differentiation for green power produced during periods of relative scarcity/abundance. Additional structural barriers that contribute to distorted real-time price signals, including uneven spot market maturity, limited transparency on cross-provincial congestion. Finally, most power in China is still transacted via a medium/long-term power contract, with buyers seeing only moderate exposure to prices in the real-time market, even in provinces with formally operating spot markets. These factors undermine the fidelity of wholesale price signals, which are foundational for time-resolved procurement, storage value realization, and credible clean energy accounting.

6.1.2. PHYSICAL INFRASTRUCTURE: TEMPORAL AND SPATIAL SHIFTING CAPACITY

China's physical infrastructure for temporal and spatial shifting of electricity is robust and expanding but differs across regions and still faces gaps relative to the pace of renewable buildout. On the temporal shifting side, cumulative energy storage capacity continues to grow, with "new type storage" (predominantly lithium ion battery energy storage systems) accounting for most of the recent additions. National policy has elevated new type storage as a core strategy, with a stated target of around 180 GW by 2027, signaling a shift away from mandatory renewable co location toward more market driven deployment following Document No. 136.

On the spatial shifting side, China has built an extensive network of long-distance HVDC and UHVDC/UHVAC transmission lines that enables large interprovincial power flows between renewable rich regions and major load centers.

22. NDRC and NEA, *Basic Rules for the Medium-to-Long-Term Electricity Market,* NDRC Energy Regulation [2025] No. 1656

Recent pilots have also begun to test more frequent dispatch optimization across provincial boundaries (including 15-minute optimization in specific cross provincial transactions). This indicates incremental progress toward dispatch coordination beyond single province balancing. However, cross provincial trading remains constrained by institutional barriers, limited real time transparency on transmission availability, and the continued dominance of planned or long term scheduled utilization for many transmission corridors.

Despite significant infrastructure investment, curtailment risks persist in parts of northwest China and interprovincial transactions can remain difficult to execute at scale, particularly during periods of system stress.

6.1.3. MARKET MECHANISMS: REAL-TIME PRICE SIGNALS

China's GEC system covers all renewable generation types, with current practice based on monthly certificate issuance and annual matching for consumption claims. New rules effective from January 2026 require GEC-backed claims to align the generation year with the consumption year, establishing same-year matching as the official baseline. While higher temporal precision is encouraged over time, there is no binding timeline for implementation.

Factory-level pilots in Guangzhou and Yantai have proven technical feasibility by layering time-stamped data onto monthly certificates. At provincial scale, Jiangxi has operated an hourly green power trading and traceability system since 2025, using a blockchain to generate verifiable hourly consumption certificates for CBAM compliance.

Jiangsu introduced a pilot for hourly green power trading in its 2026 MLT market rules (issued 28 February 2026). The rules envisage dedicated trading sessions for voluntary buyers and sellers to agree on hourly electricity volumes and prices, specifying that the environmental attributes of such transactions are to be settled on an hourly basis. At the same time, China's GECs remain issued on a monthly basis, so the Jiangsu approach effectively separates hourly environmental value settlement and traceability for participating trades from monthly certificate issuance under the national framework. The rules also give a nod to retailer-provided "hourly green power" retail packages, with retail companies allocating hourly green volumes to contracted end-users with such a demand.

However, critical gaps remain for scaling granular tracking beyond pilots. First, GECs are still issued as monthly instruments and do not include built-in hourly timestamps. Second, even as its importance is increasing with the expansion of spot markets and time-resolved procurement needs, access to high-quality hourly generation and consumption data suitable for third-party verification is inconsistent across provinces and customer segments. Third, standardized contractual and settlement pathways for physically delivered, time-stamped clean electricity are only beginning to emerge. Experience from spot market evolution and pilot initiatives (including AsiaREC) demonstrates that access to high-quality data and time-resolved contracting is already feasible, but wider adoption will depend on continued market development and policy support, which will be uneven across provinces.

6.1.4. POLICY COORDINATION: MANDATED DEMAND AND VALUE RECAPTURE

Policy coordination is a key enabler for RTC aligned procurement. While the "green power demand" side and "attribute recognition" side of green electricity consumption are increasingly integrated in China, the "value recapture" side (where the temporal value and flexibility value are actually monetized) remains institutionally and commercially distinct.

On the demand side, 2025's Document No. 262 mandates key energy intensive sectors and data centers increase their green power consumption ratios over time, with a mid-term target of meeting levels no lower than the national average RPS by 2030.[23] On the recognition side, GECs are designated as the sole official proof of green power use and are recognized by RE100 for voluntary renewable electricity claims. On the value-recapture side, complementary mechanisms such as capacity pricing,[24] ancillary services markets, and expanding spot market/ToU reforms provide channels to compensate flexibility and reliability, but these mechanisms are not yet systematically linked to RTC-style products or time-based clean electricity claims.

Against this backdrop, the remaining gaps largely take the form of coordination and rule-design questions rather than a lack of pilots. In other words, the near-term opportunity for sector stakeholders is to translate existing demand signals and pilots into clearer, more standardized approaches that can be replicated across provinces.

- First, publish a clear, standard definition of RTC (or "hourly-matched") clean power products for China that is compatible with the existing GEC framework and also usable for voluntary disclosure to investors or export partners. A shared definition would increase market confidence and provide a practical basis for replicating pilots across provinces.
- Second, clarify how "firming" and time shifting (e.g., storage-enabled delivery and portfolio aggregation) can be treated within claim rules, so that physical delivery can be linked to a recognized clean-attribute claim with clear anti-double-counting controls. This would provide greater certainty for buyers, retailers, and storage providers and support the development of firmed, time-shaped green power products.
- Third, strengthen cross-institutional coordination among the bodies responsible for green consumption mandates, market settlement, certificate administration, and metering/data governance. A clear division of roles, aligned data standards, and coordinated MRV procedures can accelerate scale-up of robust verification practices and help translate existing demand signals and flexibility mechanisms into RTC-oriented procurement platforms.

23. NDRC et al., *Opinions on Facilitating High-Quality Development of the Renewable Energy GEC Market*, NDRC Energy [2025] No. 262.
24. For example: NDRC & NEA, *Notice on Establishing a Capacity Pricing Mechanism for Coal-Fired Power*, NDRC Price [2023] No. 1501.

6.2. GRANULAR MATCHING CAN SUPPORT RENEWABLE-FRIENDLY SYSTEM DESIGN

Several of the stresses now emerging in China's provincial power systems, including re emerging curtailment risk, periods of very weak or negative spot settlement prices, solar-driven intra-day ramps ('duck curve' dynamics), and persistent difficulty monetizing flexibility (especially storage) are time-dependent problems. They show up in specific hours, not in annual averages. In this moderately-advanced phase of China's power market reforms, the merit of granular matching becomes clearer: it can help connect clean-power claims and procurement to the same hourly patterns that are already driving prices, curtailment rates, and the value of flexibility, instead of the current volumetric approach, which treats all renewable MWh as interchangeable within a month or year.

Granular matching is not a substitute for broader market reforms, but it plays a critical role in tightening the temporal link between things that must synchronize in order for renewable-friendly system design to advance, namely: physical delivery, commercial settlement, and MRV for renewable consumption claims. The discussion in this section focuses on the system-design objectives that will be supported by making that linkage explicit, namely:

- Managing solar-driven daily ramps by creating incentives for storage and flexible loads to absorb midday surpluses and transfer them to evening peaks (near-term/already emerging)
- Reducing balancing actions and dispatch interventions by better aligning price signals with daily system conditions (near-term/already emerging)
- Enabling firmed renewable products to be offered in the power market (e.g., solar-plus-storage) by making temporal attributes explicit for both energy settlement and clean attributes (near-term, but province-dependent)
- Improving transparency around system investment needs and bottlenecks (medium-term)
- Strengthening MRV by aligning metering, market settlement, and certificate registries for time-based claims (medium-term)

Taken together, these objectives are not only operational in nature; they are also an explicit system-design choice to improve overall economic outcomes for system stakeholders. By better aligning clean procurement signals with the hours that drive dispatch decisions, scarcity, and congestion, granular matching can help reduce the need for inefficient interventions, lower the system costs of balancing and curtailment, and support a least-cost pathway for maintaining reliability as renewable penetration rises.

6.2.1. ADDRESSING SOLAR-DRIVEN INTRA-DAY RAMPS

In Chinese provinces with high solar penetration, spot markets increasingly exhibit the characteristic of midday surplus followed by rapid evening ramps. More granular settlement and time-bound clean procurement efforts can reinforce incentives for resources that absorb surplus (e.g., storage charging, flexible industrial loads, EV charging) and for resources that provide ramping and peak support (e.g., storage discharge, demand response). For system operators, the practical value of more granular signals is improved alignment between operational needs (ramp, reserves, congestion) and the economic signals seen by market participants.

6.2.2. REDUCING SYSTEM BALANCING ACTIONS (AND COSTS)

When renewable attributes and procurement practices are primarily resolved annually or monthly, they may be weakly connected to the hours in which the system experiences scarcity, congestion, or rapid ramps. By contrast, time-delimited approaches, combined with market settlement rules that allow accurate reflection of intra-day supply conditions, can strengthen incentives for load shifting and flexibility participation. This is particularly true in the hours when they reduce balancing actions (e.g., fewer manual dispatch interventions, softer ramping requirements, or decreased reliance on out-of-merit commitments). The size of the impact will depend on local market design and operational constraints across Chinese provinces, but improved alignment between incentives and real-time system conditions is the prerequisite.

6.2.3. ENABLING FIRMED RENEWABLE PRODUCTS

A practical pathway toward RTC supply is the combination of variable generation with storage and/or diversified portfolios. In China, this aligns with the recent expansion of green power direct supply and hybrid "*source-grid-load-storage*"[25] project models, which are designed to pair variable generation with controllable assets. However, to date, these configurations are more visible as conceptual system-integration models than as standardized buyer-facing products for corporate procurement.

Granular market design will support their development by making the time dimension explicit. It becomes clearer which hours require firming and which hours are structurally oversupplied. For industrial buyers with increasing exposure to spot-linked settlement, this can also improve hedging performance compared to "solar-only" procurement, by reducing reliance on the same low-price midday hours and providing a cleaner match to round-the-clock load shapes. In some project designs, combining solar with storage can also improve utilization of connection capacity by shifting part of the injected energy to higher-value hours. The extent of these benefits is highly system-specific. It depends on several factors: interconnection rules, dispatch constraints, and whether storage and hybrids can access and stack relevant revenue streams such as energy arbitrage, ancillary services, and capacity mechanism revenues.

6.2.4. IMPROVE TRANSPARENCY ON SPECIFIC INVESTMENT NEEDS

By improving transparency around when the system is short or long and linking those conditions to settlement and (where relevant) green attributes, granular design can help grid planners and market participants alike. It can help them identify flexibility investment opportunities such as storage, demand response, controllable load in the grid's most exposed pinch points. Over time, this supports a shift from capacity-focused expansion toward asset portfolios that are optimized for adequacy, ramping, and congestion management. This is consistent with China's national unified power market agenda, where policymakers have highlighted the value of improved system transparency to guide more coherent system investment. Although the effectiveness of these signals still relies on the existence of enabling regulations, like market access and settlement exposure, the ideal outcome is to reduce reliance on administrative dispatch interventions and to improve the efficiency of investment outcomes.

25. Directly translated from "源网荷储" in Chinese.

6.2.5. IMPROVING MRV DATA CREDIBILITY

Improving the credibility and interoperability of electricity data MRV is an important medium-term objective of China's power market reform, particularly for export-oriented value chains facing rising expectations for verifiable electricity-related emissions evidence. While system operators focus on dispatch, an important practical objective of the power system is ultimately to meet the commercial needs of its power buyers. For many large power users, this now includes the ability to demonstrate credible, auditable clean electricity usage to customers, regulators, and overseas markets.

Trade-linked requirements (e.g., CBAM/RFNBO) are external to domestic dispatch priorities, but they amplify the value of auditable, time-bound data and can accelerate demand for consistent MRV practices. Over time, more consistent MRV and data interoperability can help translate policy objectives into implementable market and accounting practices (like support for exporter competitiveness and improvements to the credibility of green consumption claims).

6.3. GRANULAR MATCHING AS A KEY MILESTONE IN MARKET MATURATION

On a system level, granular matching acts as a key milestone in the evolution of a reform-oriented power sector. As pricing, dispatch, and market participation become more time-resolved, definitions of "clean electricity" and the evidence used for claims must also evolve to reflect when electricity is generated and consumed.

For China, granular matching will become increasingly relevant as existing institutions mature (including spot market pilots, evolving ToU practices, and the established GEC framework) and the national unified power market agenda progresses. While annual or monthly matching has historically been used to scale renewable consumption claims, it does not reflect the time-dependent nature of electricity systems and is therefore increasingly misaligned with emerging market conditions in China.

Moving to time-resolved accounting does not change physical dispatch by itself; rather, it upgrades the "resolution" of the procurement and green power claims, so they are more comparable to the temporal structure already used in short-term power market operations. This makes it easier for policies and eventually commercial products to distinguish hours that are already well-supplied with clean generation versus hours that still require firming and flexibility.

For policymakers, the core rationale is coordination and standardization – both signifiers of an increasingly mature and sophisticated power market. A time-resolved approach can help align metered data, market settlement intervals, and attribute issuance and claim rules, reducing ambiguity across provinces and use cases as market rules converge under the national unified power market roadmap.

Early pilots (Guangzhou and Yantai) and provincial implementations (Jiangxi and Jiangsu) confirm hourly matching is technically feasible within China's existing frameworks, but scaling depends on policy and market-rule choices rather than proof-of-concept alone. The next section translates this framing into practical recommendations aligned with China's current reform trajectory.

6.4. PRACTICAL RECOMMENDATIONS FOR RTC ADOPTION IN CHINA

This section sets out a practical roadmap for advancing RTC-oriented procurement and granular accounting in China from a system-planning perspective. In practice, implementation timeline will vary by region; some actions can be piloted immediately in provinces with operating spot markets and better data transparency, while others will require advancements in rulemaking, data governance, or registry operations. For clarity, each recommended action in the following sections includes indicative primary stakeholder "owners" for the Chinese context.

Accelerating RTC-oriented clean electricity procurement in China will require coordinated progress across market rules, data/registry infrastructure, and commercial products. The following recommendations focus on implementation choices that align with China's national unified power market objectives and the practical needs of export-oriented buyers. At the same time, this action roadmap recognizes that degrees of market maturity and data availability remain uneven across provinces.

Importantly, progress should not be measured according to "full" institutional reform. In China, a number of near-term, non-standard pathways can already be pursued through pilot arrangements (e.g., industry park-based programmes, custom retailer offerings, or limited-scope hourly matching for specific facilities). While these approaches may not be fully replicable or nationally standardized, they can still generate credible evidence for feasibility purposes, while revealing implementation barriers and supplying evidence of "best practices" for future rulemaking and registry design. In this sense, the roadmap provided can be understood as a guide for standardization, alongside an expectation that interim and ad hoc solutions will continue to play a constructive role.

6.4.1. PHASE 1 - DEFINE SCOPE, CLAIMS, AND GOVERNANCE

Phase 1 is about laying a strong foundation: defining what "RTC" (or hourly matching) means in the China context, what can be claimed, what evidence counts, and who owns the rules. The table below lists the core Phase 1 tasks and indicative owners; the later phases then move on to data and registry work, contracting pathways, pilots, and eventual standardization.

Table 4: Phase 1 Tasks: Defining Scope, Claims and Governance

No.	Task Contents	Primary Owners
1	Establish a definition for RTC/hourly-matched claims compatible with the existing GEC framework, including eligible contracting pathways, market boundaries, and minimum data requirements.	NDRC/NEA; provincial DRCs; GEC administrator/registry operator; provincial power exchanges.
2	Specify how a more granular approach can be introduced without conflicting with existing compliance tools (e.g., start with voluntary or sector-/zone-specific pilots to demonstrate how hourly evidence supplements GECs without replacing them).	NDRC/NEA; provincial DRCs; GEC administrator/registry operator.
3	Identify priority use cases for early implementation (some reasonable options would include export-oriented manufacturing zones, data centres, and other power buyers with smart metering) and publish a clear scope statement on the intended outcomes and findings of the pilot cases.	Provincial governments/DRCs; industrial park administrators; large buyers/exporters; power retailers.
4	Where relevant, consider whether existing demand drivers (mandatory and voluntary green procurement schemes, green financing guidelines, etc.) could give recognition to higher temporal accuracy without imposing undue compliance burdens.	NDRC/NEA; provincial DRCs; relevant finance and industry regulators.
5	Ensure institutional coordination across departments responsible for market settlement, certificate governance, and metering/data management, to reduce the likelihood of conflicting definitions or requirements across different provinces.	NDRC/NEA; provincial DRCs; power exchanges; grid companies; metering/data administrators.

6.4.2. PHASE 2 - BUILD MRV AND REGISTRY FOUNDATIONS

Phase 2 covers the data infrastructure that makes hourly claims verifiable: access to metering data, clear data governance, and a way to link that data to settlement and GEC issuance/retirement. The table below summarizes the core tasks and indicative owners.

Table 5: Phase 2 Tasks: Constructing the MRV and Registry Foundation

No.	Task Contents	Primary Owners
1	Upgrade the GEC registry and associated processes so time-stamped information can be attached to claims (e.g., via hourly metadata linked to monthly issuance), with clear rules for issuance, transfer, and retirement.	GEC administrator/registry operator; NEA; provincial implementing bodies.
2	Establish consistent, auditable linkages between the time of metered generation/consumption, market settlement intervals, and certificate issuance/retirement records.	grid companies/metering systems; power exchanges/settlement; GEC registry; third-party verifiers.
3	Develop technical guidance for hourly-based power contracting and verification, with explicit alignment to export/trade-linked evidence requirements where relevant (e.g., CBAM/RFNBO).	provincial DRCs; industry associations; verifiers; large exporters/buyers; power exchanges.
4	Define basic MRV controls to manage double counting risks when storage-enabled generation shifting, portfolio aggregation, or interprovincial sourcing is involved.	GEC registry; power exchanges; verifiers; market regulators.

6.4.3. PHASE 3 - ENABLE COMMERCIAL CONTRACTING PATHWAYS

Phase 3 focused on turning the accounting concepts into something buyers can actually sign, including contracting structures that fit China's retail market, plus a clear "evidence pack" (metering, settlement, and delivery records) that supports time-bound claims. The table below lists the main tasks and indicative owners, including how to handle deviations, curtailment adjustments, and firming.

Table 6: Phase 3 Tasks: Creating Contracting Pathways

No.	Task Contents	Primary Owners
1	Develop contracting pathways that can support time-bound claims in the Chinese context (e.g., how to scale sleeved PPAs between generators, retailers, and end-users to enable CBAM-compliant claims, how deviation/imbalance treatments are allocated, etc.).	Power exchanges; retailers; provincial DRCs; large buyers.
2	Clarify how green supply "firming" (including the use of storage or portfolio approaches) is treated for claim purposes, and what minimum evidence must be provided by sellers to enable buyers to make time-bound firm green power claims.	GEC registry; power exchanges; verifiers; market regulators.
3	Encourage generators and developers participating in RTC pilots to ensure interval metering and basic data quality are sufficient for verification.	Generators/developers; grid companies; verifiers

6.4.4. PHASE 4 - PILOT, EVALUATE, AND SCALE ACROSS PROVINCES

Once the foundational architecture is established in Phases 1-3, Phase 4 is about operating pilots in the provinces that are most ready, learning what breaks, improving the model, and then scaling. The table below summarizes the key tasks and indicative owners.

Table 7: Phase 4 Tasks: Setting up and Learning from Pilots

No.	Task Contents	Primary Owners
1	Select pilot regions and use cases where conditions are most conducive (e.g., operating spot markets, advanced metering, concentration of export-oriented loads).	Provincial DRCs/governments; power exchanges; grid companies; large buyers/exporters.
2	Use pilots to test feasibility and identify practical implementation barriers then refine guidance accordingly.	Pilot coordinators (exchanges/DRCs); registry administrators; verifiers; participating buyers/retailers.
3	Execute broader step-by-step rollout based on pilot learnings (e.g., first for voluntary markets, then for specific sectors, and then finally wider recognition), aligned with the national unified power market roadmap.	NDRC/NEA; provincial DRCs; registry administrators.
4	If interim bespoke arrangements yield useful operating experience, capture lessons learned and translate them into guidance for subsequent pilots or the formal "full" implementation.	Retailers; buyers/exporters; verifiers; provincial pilot coordinators.

6.4.5. PHASE 5 - STANDARDISE AND ALIGN WITH EXTERNAL STAKEHOLDERS

Phase 5 is about making the approach repeatable, setting standard definitions, disclosure expectations, and verification practices that hold across provinces. The table below sets out the main standardization and alignment tasks and indicative owners.

Table 8: Phase 5 Tasks: Standardization and Alignment

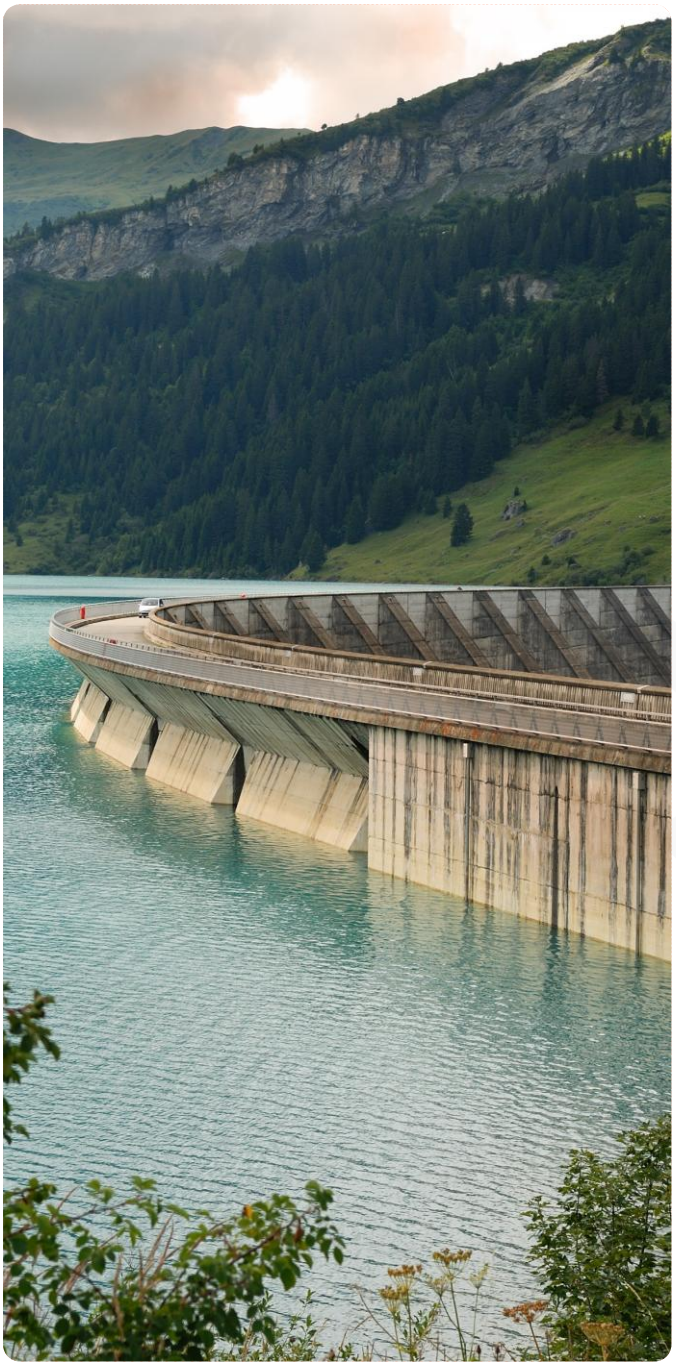
No.	Task Contents	Primary Owners
1	Provide clear disclosure guidance for time-bound green consumption claims (what can be claimed?) to reduce confusion as voluntary uptake grows.	Relevant regulators; industry associations; verifiers; large buyers
2	Where trade-linked requirements are a priority (e.g., CBAM/RFNBO exposed producers), align domestic evidence and verification pathways to external (international) institutional requirements while maintaining compliance with China's existing institutions.	NDRC/NEA and relevant ministries; exporters / industry groups; verifiers; registry administrators.
3	Maintain regular structured stakeholder engagement to ensure definitions and standard practices are consistently evolving and reflecting new information from the pilots	NDRC/NEA; provincial DRCs; exchanges / registries.
4	As implementation matures, consider whether granular matching should be recognized in other targeted policy tools (e.g., procurement preferences for state-owned enterprises or integration into green financing eligibility frameworks), either as a requirement or an optional "higher quality" characteristic.	NDRC/NEA; provincial DRCs; green finance authorities

07.

CONCLUSION

China's power-sector reforms over the past decade have delivered meaningful change. The country has moved away from a purely administrative model, introducing competitive retail participation for large users, and making tangible progress on spot-market pilots, new storage deployment, and renewable integration. There substantial shifts are not cosmetic; they are fundamentally reshaping how electricity is priced, traded and managed with hourly effects visible in a growing number of provinces.

At the same time, the report identifies a clear gap. The operational reality in the power sector is already becoming more time-resolved, as evidenced by dispatch practices, spot settlement, and the growing visibility of intra-day scarcity and oversupply. At the same time, the country's mainstream green-attribute tools and procurement conventions remain largely volumetric and non-granular on a temporal basis. Addressing that mismatch becomes more obvious and pressing once it understood that the hardest problems in a high-renewables system are typically not about annual volumetric totals, but about specific constraints in certain hours of a 24-hour cycle.



The encouraging conclusion is that this challenge can be tackled in a phased way across key regions. The foundations needed for more granular matching are already developing across China. More provinces are moving into formal spot-market operations, interval metering and settlement data are becoming more central to market administration, and pilots are already demonstrating how hourly evidence can be layered onto existing certificate processes without discarding the national GEC backbone.

The remaining work is therefore less about inventing brand-new concepts, and more about making certain mechanisms more routine and standardized, especially data access, registry linkages, and clear, repeatable rules for what can be claimed.

More granular approaches will be beneficial for two interrelated reasons. First, they align clean procurement and investment signals with the domestic system's actual needs. This helps incentivize flexibility and firming during the most valuable hours, leading to reduced curtailment, better ramp management, and improved reliability. Second, international trade frameworks are beginning to demand time-stamped evidence for certain use cases. This is notably true for CBAM's conditions regarding market-based electricity emissions values and the EU's RFNBO requirements for green hydrogen starting in 2030. China's exposure varies by sector today, but the direction of travel is toward stricter evidence expectations.

In short, China has no lack of momentum or policy tools. What it lacks today is a consistent bridge between the hourly world in which the system already operates, and a monthly/annual world of its green attributes and claiming regime. Building that bridge is feasible if approached as a sequence of practical decisions about definitions, MRV, registry treatment, and contracting, first with tests and pilots in the highest-readiness regions, and then scaled and standardized. Section 6.4 sets out one such pathway. The key task now is to build the systems that allow accounting to catch up to physics.

APPENDIX A: BARRIER-AND-SOLUTION REGISTER FOR GRANULAR ACCOUNTING

This appendix provides a consolidated register of barriers to implementing granular (time-resolved) clean electricity accounting and RTC-aligned procurement in China, together with indicative solution directions. Items are categorized by the main enabling layer and mapped to relevant sections of this report to help readers locate the supporting discussion.

Enabling Category	Barrier (Problem Statement)	Why It Matters for Granular / Rtc Claims	Potential Solution Direction(s)	Related Section(s)
Market mechanisms	Limited buyer exposure to short-term settlement; much volume remains under MLT contracts with weak intra-day price visibility.	Without time-resolved settlement exposure, incentives to value "hard-to-supply" hours are muted and hourly products are difficult to price.	Expand market-linked retail offerings; strengthen deviation/imbalance settlement against short-term prices; phase in broader ToU-to-market alignment where feasible.	1.4; 6.1.1; 6.4
Market mechanisms	Administrative price caps/collars and benchmark anchoring constrain scarcity signals.	RTC value relies on differentiated scarcity hours; capped prices can reduce spreads needed for firming and flexibility investment signals.	Clarify and gradually relax administrative constraints; publish transparent rules for interventions to reduce uncertainty.	1.4.2; 6.1.1
Physical flexibility	Storage value capture is constrained by market access, dispatch rules, and limited revenue stacking (not just installed capacity).	Firmed/RTC delivery often depends on storage; if storage cannot respond to price signals or earn predictable revenues, firming products remain niche.	Expand storage participation rights; standardize ancillary services and capacity-style mechanisms; clarify charging/discharging and settlement treatment for firming.	4; 6.1.2; 4.3
Interprovincial delivery	Limited transparency on transmission availability; cross-provincial trading remains institutionally constrained and often planned/scheduled.	RTC claims that rely on remote renewables require credible physical delivery and settlement; opaque constraints complicate both procurement and verification.	Improve publication of corridor availability and curtailment adjustments; develop clearer transmission allocation rules for marketized trades; expand regional optimization pilots.	1.4.6; 6.1.2
Data & MRV	Inconsistent access to settlement-grade interval data for third-party verification (generation and consumption).	Hourly matching requires auditable evidence; without governed access, claims remain pilot-scale or rely on bespoke data sharing.	Define data governance and access pathways (who can access what, on what basis); standardize data formats; enable verifier access with audit trails.	6.1.3; 6.2.5; 6.4.2

Enabling Category	Barrier (Problem Statement)	Why It Matters for Granular / Rtc Claims	Potential Solution Direction(s)	Related Section(s)
Certificates / registry	GECs are issued monthly and do not embed hourly timestamps; rules for layering timestamps are not standardized nationally.	Without a registry-compatible time-stamping approach, hourly evidence cannot be consistently linked to attribute issuance/retirement and may face credibility challenges.	Enable a "timestamp layer" linked to GEC retirement (interim); define reconciliation rules between monthly totals and hourly series; specify audit and anti-double-counting controls.	3.4; 6.1.3; 6.4.2
Definitions & claims	No standard national definition for "RTC" / "hourly-matched" product compatible with Chinese market structures and external reporting needs.	Inconsistent definitions reduce replicability across provinces and increase greenwashing/credibility risk.	Publish a baseline claim taxonomy (hourly matched, portfolio-based firming, buyer-side firming, etc.); define minimum evidence and disclosure; align with major external frameworks where relevant.	6.1.4; 6.4.1; 6.4.5
Firming treatment	Unclear treatment of storage-enabled shifting and portfolio aggregation in claim rules (what counts as "delivered" and how to prevent double counting).	Firming is central to RTC products; ambiguity undermines credibility and slows product development.	Define rules for charge/discharge attribution, losses, and time-shifting boundaries; require interval evidence and clear retirement logic; specify acceptable portfolio methodologies.	4.3; 6.1.4; 6.4.2–6.4.3
Contracting pathways	Prevailing retail structure (separate generator–retailer–customer contracts) does not map neatly onto "qualifying PPA" concepts used in some external regimes.	Even if data exists, buyers may lack a recognized contractual pathway to evidence physical hourly delivery and claim validity.	Develop standard contract templates (including tripartite structures) and clear evidence packages (metering, grid-connection confirmation, settlement records) for time-bound claims.	5.2.1–5.2.2; 6.4.3
Governance	Fragmented institutional responsibilities across markets, certificates, metering, and verification; uneven provincial implementation.	Scaling requires consistent rules and data governance; fragmentation increases compliance costs and reduces replicability.	Create a coordinated governance approach for pilots; clarify ownership of definitions, data access, registry changes, and verifier accreditation; share pilot learnings across provinces.	6.1.4; 6.4.1

APPENDIX B: DEEP-DIVE OF CHINA'S POWER MARKET REFORM HISTORY

B 1. REFORM HISTORY OF CHINA'S POWER MARKETS

B.1.1. The Birth of the Modern Chinese Power Sector

Before 2015, China's power sector operated under a "Quasi-Single Buyer" model.[26] While the generation and transmission segments had been unbundled for many years thanks to 2002's Document Number 5,[27] the generation sector also featured a variety of State-Owned Enterprises (SOEs) and Independent Power Producers (IPPs). Despite this, the state-owned grid companies remained the sole off-taking counterparties in the pre-2015 Chinese power sector. Under this model, the grid companies purchased wholesale power from generators at policy-regulated rates ("the on-grid tariff") and sold retail power to end users at policy-regulated rates ('the catalogue tariff')". Meanwhile, retail competition was non-existent.

Dispatch organizations, which operated under State Grid, had a more prominent role in setting dispatch schedules and performing safety audits for dispatch plans, but information on their dispatch operations and audits was non-public and difficult to track.

While such an integrated model offers advantages for energy price stability, this regulate-ed structure was incompatible with the needs of a power system that intended to rapidly expand its renewable energy resources, struggling to reflect real generation costs in power pricing amid fluctuating supply with intermittent renewable output and demand. The lack of market-driven pricing negatively impacted investment efficiency, ultimately leading to structural capacity oversupply around 2015.

26. Pilot direct power trading between large C&I users (above 66 kV or 110 kV) and power generators was launched in a few provinces before 2015, but the trading volume was limited.
27. State Council, *Plan for Electric Power System Reform,* State Council [2002] No. 5.

The need to modernize the Chinese power system prompted the release of the seminal Document No. 9 in 2015.[28] Doc No. 9's sweeping reforms to the way power was bought and sold in China was a necessary and critical milestone on the path to market liberalization and the construction of the modern Chinese power market. Doc No. 9 included major reforms to the power sector across the following strategic areas:

- **Role of grid companies:** Grid companies were restructured and their status as a monopoly supplier of power to the commercial and industrial (C&I) sectors was eliminated. Their overall work scope narrowed to focus on T&D services, grid security, fair access, and power retail services for non-contestable power buyers. The power exchanges were also made nominally independent from the grid companies, although some operational linkages in some provinces. The grid companies were required to divest power exchanges to less than 50% share by 2020 and the power exchanges established independent boards of directors.
- **Competitive wholesale and retail markets:** The MLT power market was introduced, as well as a power spot market and a competitive retail market.[29] Power retailers (both gen-tailers and independent power retailers) were established. Power users gained the ability to negotiate power prices directly with generators or retailers.
- **Unbundling of T&D tariff:** The reform package decoupled grid revenues from trading spreads and established independent T&D tariffs based on a transparent "cost plus reasonable return" mechanism.

B.1.2. The Cultivation of the Modern Chinese Power Sector

The next major reform milestone arrived in 2021, which saw several key reform documents. First, Document 1093 (July 2021) strengthened ToU pricing as a regulated, catalogue-tariff demand-side instrument. Then, Document 1489 (August 2021) introduced green power trading, which would begin scaling the year after. Finally, Document 1439 (November 2021) was issued to mitigate the disruptive impact of the coal/power market supply crunch in Q3 2021.[30]

Document No. 1439 specifically fast-tracked the implementation of several major reforms that had already been discussed by policymakers for several years. The key elements of this milestone reform document included:

- **Market access reform and expanded price fluctuations:** All coal power generation should be sold via power market trading, with the price determined within +/-20% floating range of the local coal benchmark base tariff in the MLT market.[31] The fluctuation of the steam coal price was also more fully directed to the power market, increasing the power price exposure coal price volatility. The annual guaranteed quota for coal plant dispatch hours was abolished. This increased RE competitiveness as part of the power demand was released, and this also eliminated the phenomenon of RE generators having to buy generation rights from coal plants.
- **Mandatory market participation for C&I users:** The C&I "catalogue tariff" was officially cancelled. All C&I users with a 10kV connection or higher must purchase power via market channels, purchasing from either generators (as wholesale buyers) or power retailers (as retail buyers). C&I buyers that had not yet entered the power market will be enrolled by default in the so-called "grid-delegate" scheme, whereby the local grid company will serve as the purchasing agent and sell power at a non-negotiable price updated monthly.

28. CPC Central Committee & State Council, *Several Opinions on Further Deepening Electric Power System Reform,* CPC Central Committee [2015] No. 9.
29. The MLT market includes products with tenors between two days and a year. Spot markets comprise intra-day and day-ahead trading.
30. NDRC, *Notice on Further Deepening the Market-Oriented Reform of Coal-fired Generation On-Grid Electricity Prices,* NDRC Price [2021] No. 1439.
31. The previous price formula allowed for fluctuations of +10%/-15% in theory; in practice however, it had never been used, and so the new floating range adjustment was also notable in that it began adjusting prices according to the allowable floating range for the first time.

- **ToU reform:** Despite the abolition of C&I catalogue tariffs, the regulated ToU scheme remained in effect, with ToU periods treated as blocks. Provincial regulators periodically revised ToU curves according to grid conditions, RE penetration rates, power prices, and overall power supply and demand.

The ToU system established by Doc. 1439 persisted until early 2026, when a phase-out of the regulated scheme was announced. In its place, retail suppliers and large users will rely on market-based settlement (especially spot-market-linked pricing), with time-varying prices formed through market clearing rather than administratively defined blocks. This shift is key for promoting round-the-clock clean power because it strengthens hourly price signals that reward flexibility (storage and demand response) and makes it easier to structure, price, and verify hourly clean products.

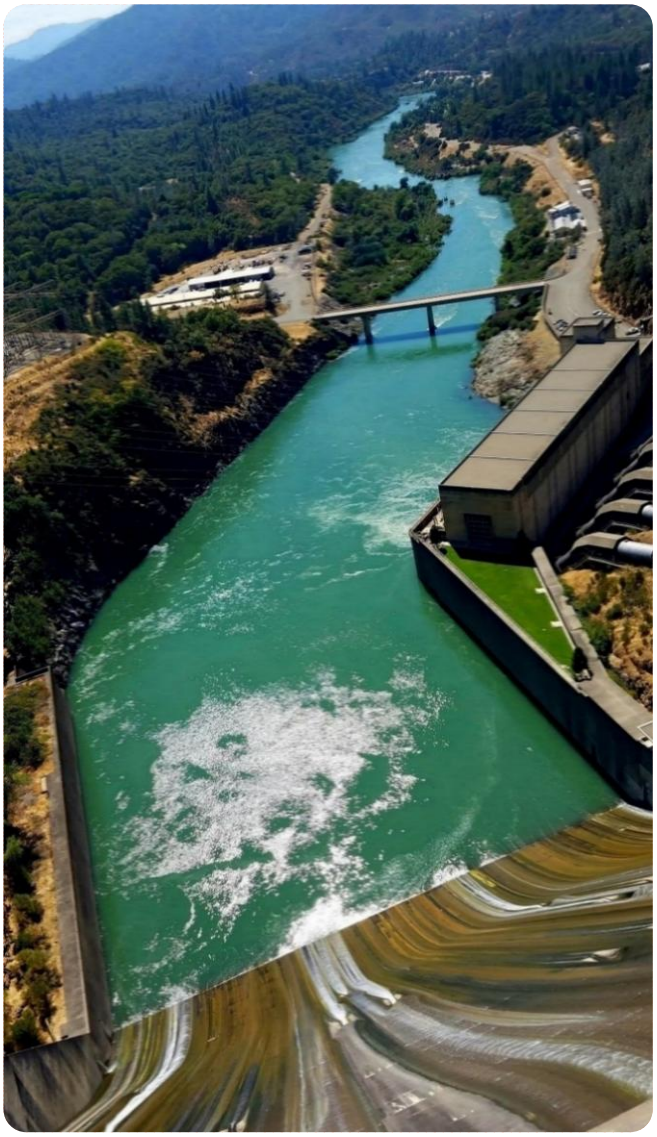
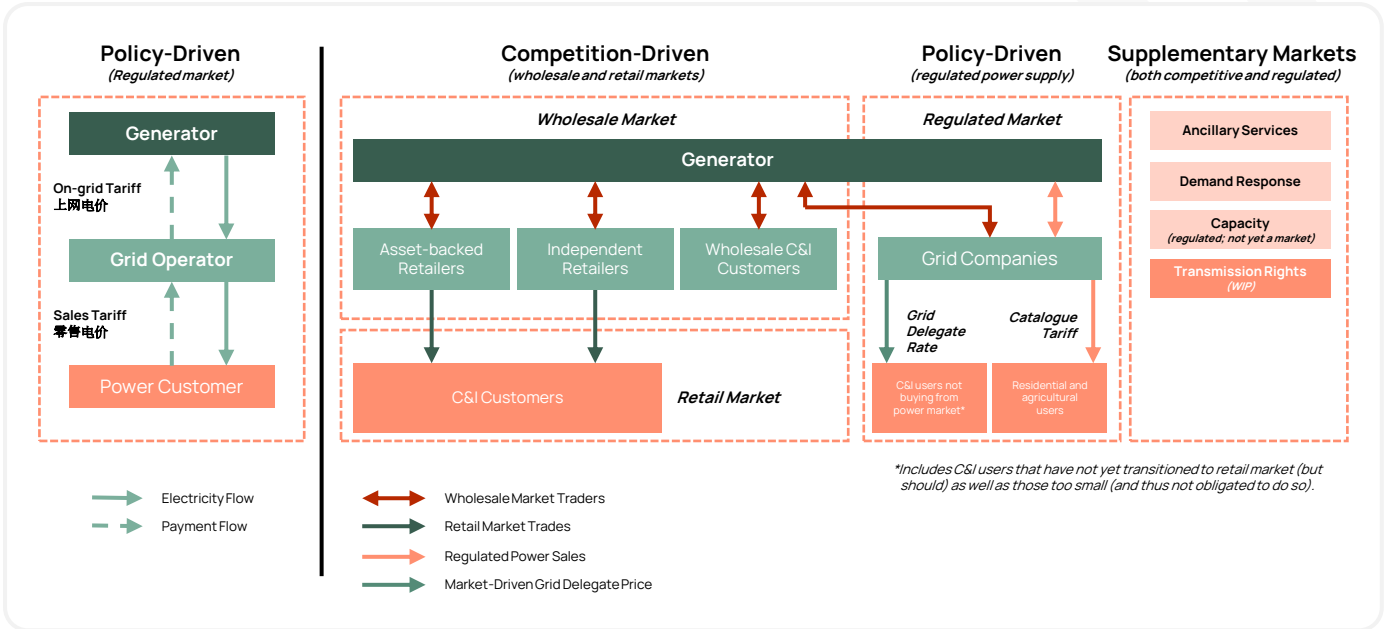


Figure 12: Pre/Post 2021 Chinese Power Market



Source: The Lantau Group

B.1.3. China's Power Sector Path to Maturity

From 2023 to early 2026, further market liberalization progress was made in the power market, with key updates supporting a more transparent pricing mechanism and greater renewable integration:

- **Revised T&D Tariffs:** The 3rd cycle (2023-2025) for T&D review unbundled system operation costs and line losses from T&D tariffs, creating greater transparency along with a more accurate reflection of the costs associated with delivering electricity.[32] The unbundling created clearer congestion signals for the grid companies, enabling them to make more informed investment decisions. More importantly, it paved the way for future trading of distributed RE.

Distributed RE trading such as rooftop solar faced considerable resistance from the grid companies, largely because the grid 'pass-through fee' was previously a lump sum combining T&D fees with other system charges. Due to the lack of clarity in how these fees were structured, grid companies were expected to absorb part of the costs. By separating T&D fees, line-loss fees, and system operation fees, it became much clearer how much grid companies should be compensated in a distributed RE transaction. This transparency helps secure their support for the development of distributed renewable energy trading.

- **Power Capacity Compensation Mechanism:** A mechanism supplementing energy market revenues with guaranteed capacity payments for coal-fired units, gas-fired units, pumped storage hydropower and grid-side battery storage.[33]

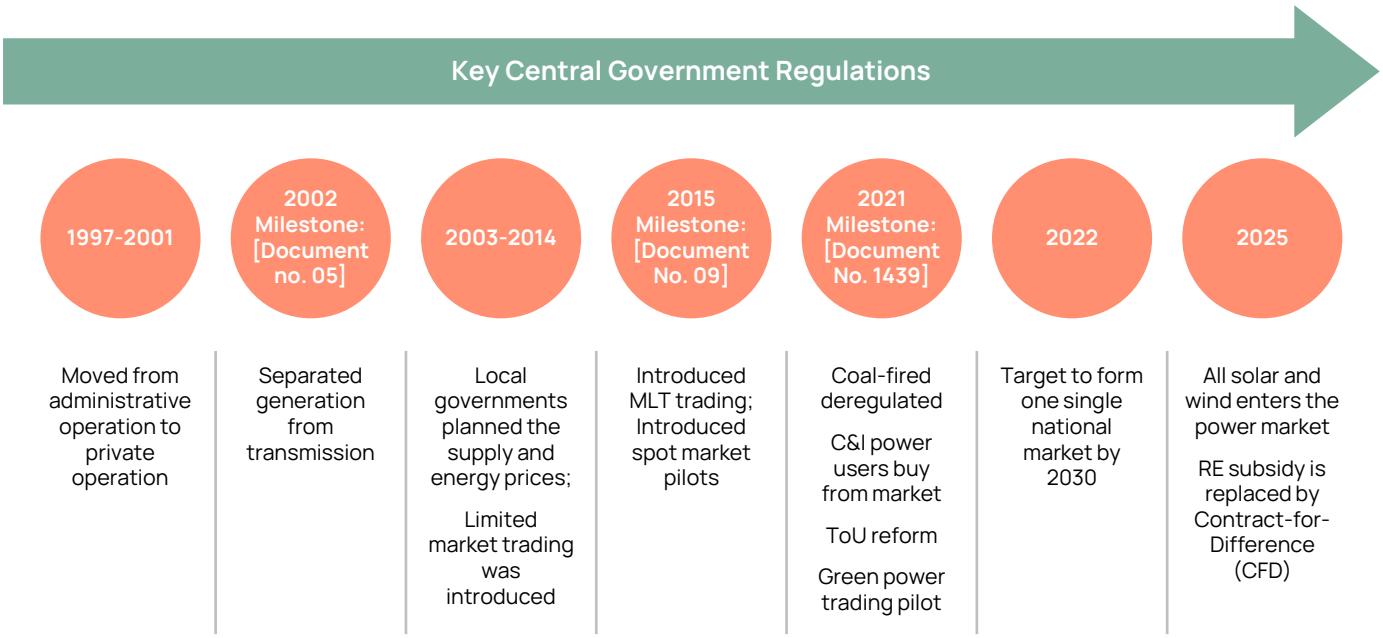
This framework, initially launched for coal projects in 2024 and expanded to broader flexible resources in January 2026, aimed to improve project bankability. Ultimately, it ensures sustainable investment of dispatchable capacity to maintain the grid resilience as renewable penetration surges.

- **Standardization of Ancillary Services Markets:** To ensure grid reliability alongside market liberalization, the NDRC issued a national-level notice for ancillary services markets. This notice clarified and standardized three key areas across regions: the pass-through mechanism, price ceiling calculation, and trading products.[34] Products covered in this notice included frequency regulation, peak shaving, and operating reserve. Each product has a regulatorily defined price cap specific to each province.
- **Deepening Market Inclusivity for Other New Entities:** The ongoing market reform is systematically expanding the regulatory definition of wholesale market entities. This enables the integration of flexible and distributed technologies, through lowering barriers to entry for standalone BESS, integrated "source-grid-load-storage" projects, direct green power supply projects, and Virtual Power Plants (VPPs).
- **T&D Tariff Mechanism for Direct Green Power Supply Projects:** Transitions from traditional two-part capacity and volumetric charges to a capacity-centric model, effectively charging T&D tariff based on the reserved connection capacity rather than electricity consumption supplied from the grid.[35]

32. NDRC, *Notice on Transmission and Distribution Prices and Related Matters of Provincial Power Grids in the Third Regulatory Cycle,* NDRC Price [2023] No. 526.
33. NDRC, *Notice on Establishing a Capacity Pricing Mechanism for Coal-fired Power,* NDRC Price [2023] No. 1501.
34. NDRC, *Notice on Establishing and Improving a Market-Based Pricing Mechanism for Power Ancillary Services,* NDRC Price [2024] No. 196.
35. NDRC, *Notice on Improving the Pricing Mechanism to Promote Local Renewable Energy Consumption,* NDRC Price [2025] No. 1192.

- **Full Integration of Wind and Solar into Wholesale Market:** All wind and solar projects are now mandated to participate in the wholesale market.[36] A CfD mechanism is introduced to secure the project's financial viability. This mechanism differentiates between pre-existing projects (maintaining historical coal base tariff within certain volume limits) and incremental projects (where guaranteed prices are established through competitive bidding with volume limits).

Figure 13: Development and Reform Summary of the Chinese Power Market



Source: The Lantau Group

B 2. THE FUTURE OF CHINA'S POWER MARKET

B.2.1. The Optimization of the Modern Chinese Power Sector

While it's still too early to identify exactly when in the future China's power will have concluded its "maturation" phase and embarked upon late-stage "optimisation", Chinese policymakers have already issued clear descriptions of what the activities in this phase will look like, along with their intended outcomes. China aims to build a unified power market that allows resources to be efficiently allocated through market supply and demand, minimising negative social costs and realising a system that can effectively accommodate high shares of clean and sustainable power generation.

The blueprint for the future power market has been charted comprehensively by two key policies, The NDRC Document No. 118, issued in 2022,[37] and the more recent State Council Document No. 4, issued in 2026.[38] The proposed implementation milestones from these two guidance documents are as follows:

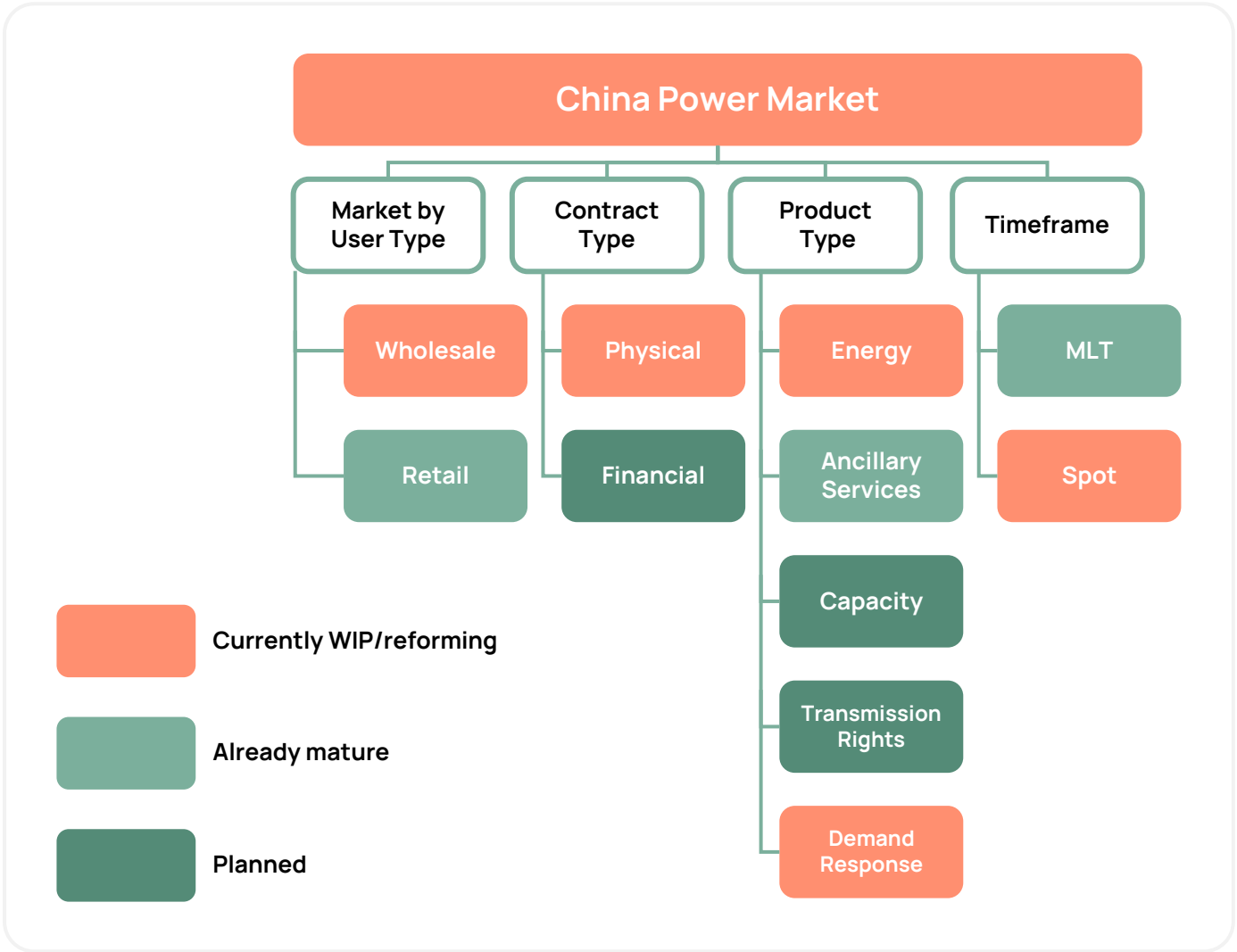
36. NDRC, *Notice on Deepening the Market-Oriented Reform of Renewable Energy On-Grid Prices and Promoting High-Quality Renewable Development,* NDRC Price [2025] No. 136.
37. NDRC, *Guidance on Accelerating the Development of a National Unified Electricity Market System,* NDRC Reform [2022] No. 118.
38. State Council, *Implementing Opinions on Improving the National Unified Electricity Market System,* State Council General Office [2026] No. 4.

Target by 2030 – Market Foundation: A nationally unified power market system is *basically* built. All generations and most electricity consumers (except protected users) will participate directly in the market. A target of ~70% of total electricity consumption is traded in the power market. Cross-province (region) and intra-province (region) markets will jointly operate, with spot markets fully and officially operating nationwide under unified rules and standards.

Target by 2035 – Market Maturity: The nationally unified power market system will be *fully built and mature*. The percentage of marketized power consumption will continue to grow. The power market will comprehensively reflect the multi-dimensional value of power resources—not just energy, but also capacity, flexibility, and environmental attributes, ensuring optimal national allocation.

Longer-term Vision: The ultimate power market is a single national power market that allows electricity prices to be determined by the market while maintaining risks at acceptable levels to ensure economic stability.

Figure 14: Status and Outlook of Chinese Power Market Structures



Source: The Lantau Group

APPENDIX C: DEEP-DIVE INTO THE STRUCTURE AND OPERATION OF CHINA'S POWER SECTOR

C1. OVERALL SECTOR STRUCTURE

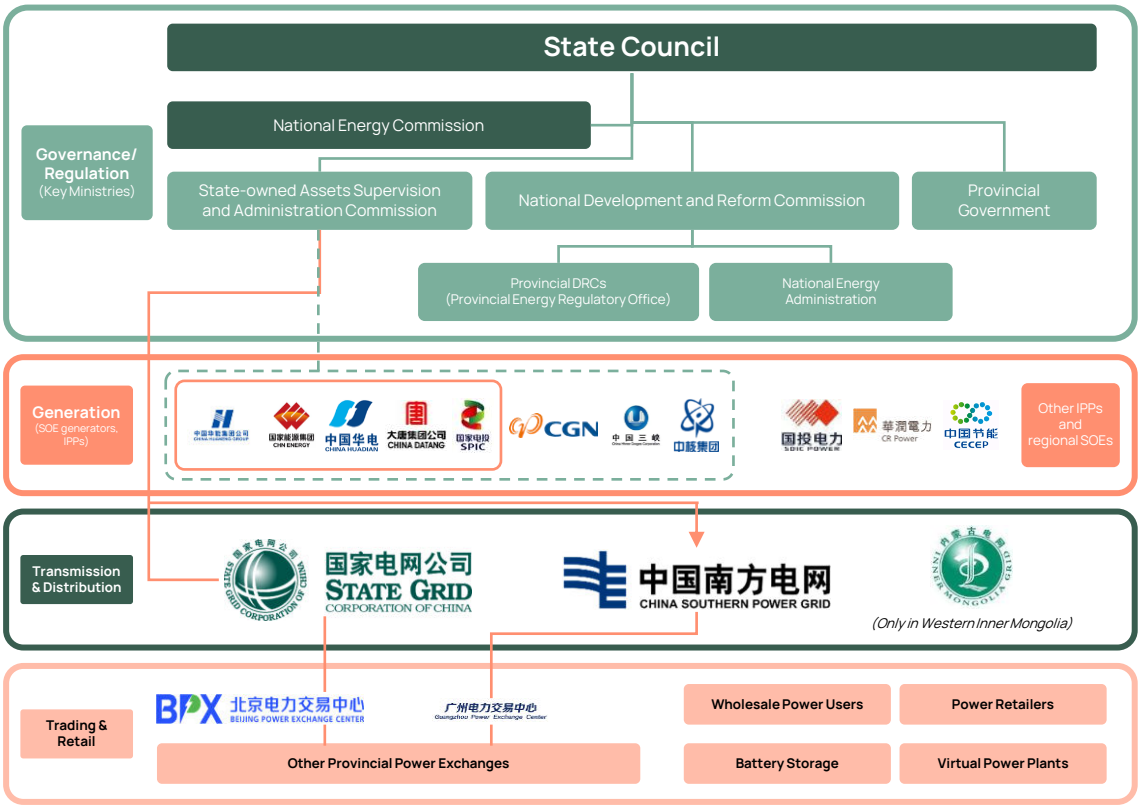
Regulatory Institutions: The State Council approves top-level strategic frameworks and overarching market goals to ensure alignment with broader national macroeconomic and energy transition policy. Under the State Council, the National Development and Reform Commission (NDRC) serves as the key economic authority for the power sector, driving institutional reform and pricing regulation. Its subsidiary, the NEA, focuses on energy policy and regulatory enforcement.

Many other ministries touch upon the power sector in smaller ways, for instance, land usage for development power plants goes through the Ministry of Natural Resources approval. National-level bodies also govern at a local level via provincial subsidiaries. All Chinese national SOEs are administered via the State-owned Assets Supervision and Administration Commission (SASAC).

Generation, T&D and Retail: Generation in China is liberalised, with many large and small SOEs and IPPs, including some foreign investors. Retail power sales are competitive, and most large power generators also have a retail business. State Grid (SGCC) and China Southern Grid (CSG) focus mostly on T&D functions and non-contestable customers.

Market and System Operators: The markets are operated by independent Power Exchanges (such as the national-level Beijing and Guangzhou Power Exchange Centres, and provincial counterparts) and Power Dispatch Centres, responsible for real-time grid security and balance. They organise market participants to conduct market trading on corresponding regional or provincial trading platforms. Market operators are also responsible for drafting market rules and providing trading settlements.

Figure 15: China Power Market Governance Structure



Source: The Lantau Group

C.1.1. Market Hierarchy and Dispatch Structure

China is a large country, with many provinces individually featuring the population size and power consumption profiles of whole countries elsewhere in the world. Therefore, the Chinese power market operates on a hierarchical system. Provincial markets are the fundamental unit for local balancing and clearing, utilising the physical infrastructure of the provincial grid network. Above this, the inter-provincial/regional market functions in a way comparable to cross-border power trading in Europe. Cross-province power dispatch allows for adjustments across grid boundaries, utilising cross-provincial transmission infrastructure. Dispatch is coordinated on a provincial level by the provincial power exchanges, while cross-provincial dispatch is coordinated by one of two regional dispatch centres, located in Beijing and Guangzhou, respectively.

China's power markets currently exhibit what could be characterised as a centralised + decentralised hybrid scheme. The grid companies and the dispatch organisations are the central operators, maintaining system stability and balancing. Power market participants trade in the power markets, forming prices via uniform market clearing prices as in most centralised power markets. Provincial markets are independent markets which trade with each other through centralised trading as the power exchanges aggregate the local demand/supply and trade with each other. In the future, both centralised and decentralised market features will be introduced, such as peer-to-peer direct trading of cross-provincial market participants, financial contracts, and encouraged submission of the peer-to-peer dispatch schedule.

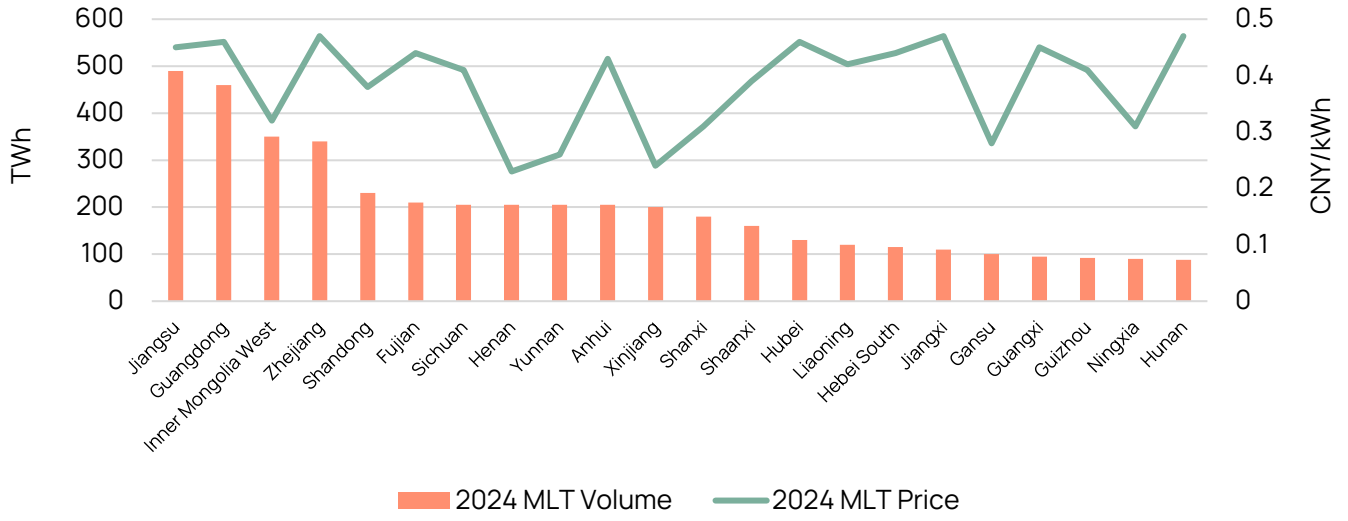
C 2. POWER TRADING

C.2.1. Wholesale Power Markets

MLT Markets

The MLT market today serves as the bedrock of the wholesale power market, stabilising prices through multi-year, annual, monthly, and intra-month contracts. Owing to the relative simplicity for market participants to understand and implement, it has served as the stepping-stone from the older regulated system to a market-driven regime. Consequently, many current policies and trading rules are designed to preserve established MLT trading practices while ensuring changes are introduced gradually and controllably.

Figure 16: 2024 MLT Trading Volume and Price



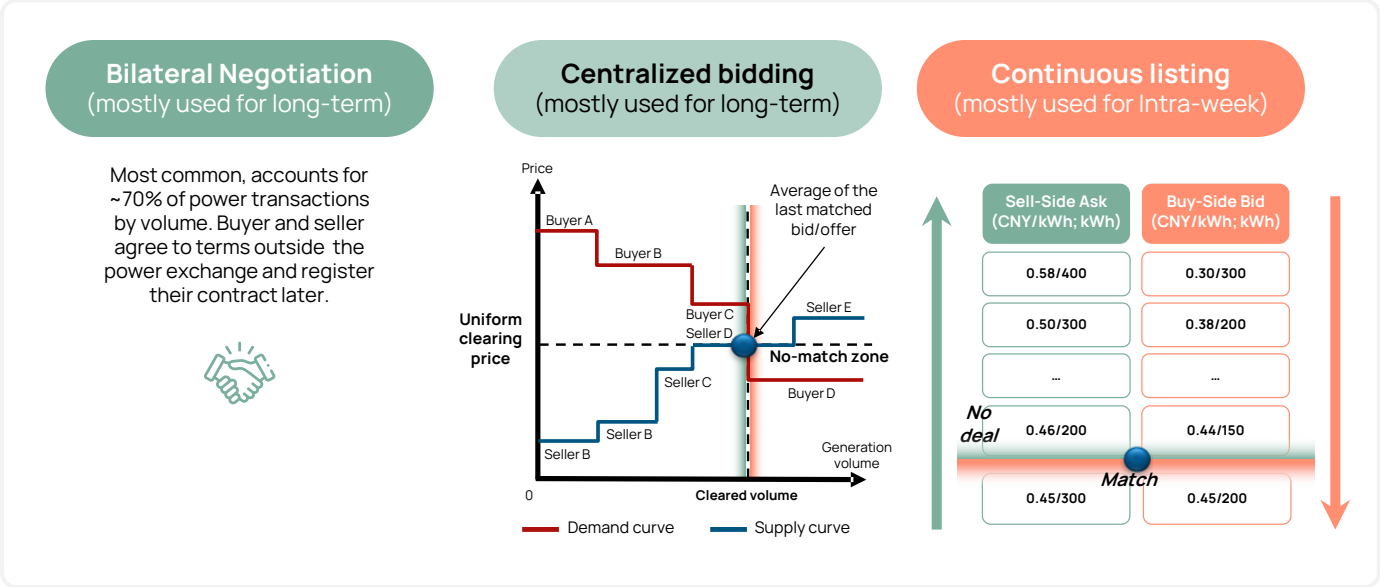
Source: NEA, 2024 Annual Report on China's Electricity Market Development

MLT contracts are financial contracts and volumes traded via MLT are dispatched on a real-time basis according to the rules of the provincial power exchange. Wholesale power market participants include generators, the grid companies, and independent power retailers, along with a handful of high-consuming wholesale end-users.

Products available in the MLT market vary across provinces. Most of the traded volume in a province is executed via bilateral negotiation, especially via annual bilateral agreements which are signed at the end of each year. Meanwhile, exchange-based centralised bidding and continuous listing models are more commonly used for monthly and intra-week trading. MLT contracts are treated as forward (financial) contracts and volumes traded via MLT are dispatched on a real-time basis according to the local power exchange's rules.

The first provincial wholesale power markets initially allowed only MLT contracting. Chinese policymakers adopted the unconventional framework of *"MLT market first, spot market later"* to ease the regulatory and practical burden of transitioning to a market-driven power trading regime. Therefore, it became possible for market participants to buy and sell power via annual or multi-month power supply contracts well in advance of the creation and operation of the spot markets.

Figure 17: Common MLT Trading Products



Source: The Lantau Group

Spot Power Markets

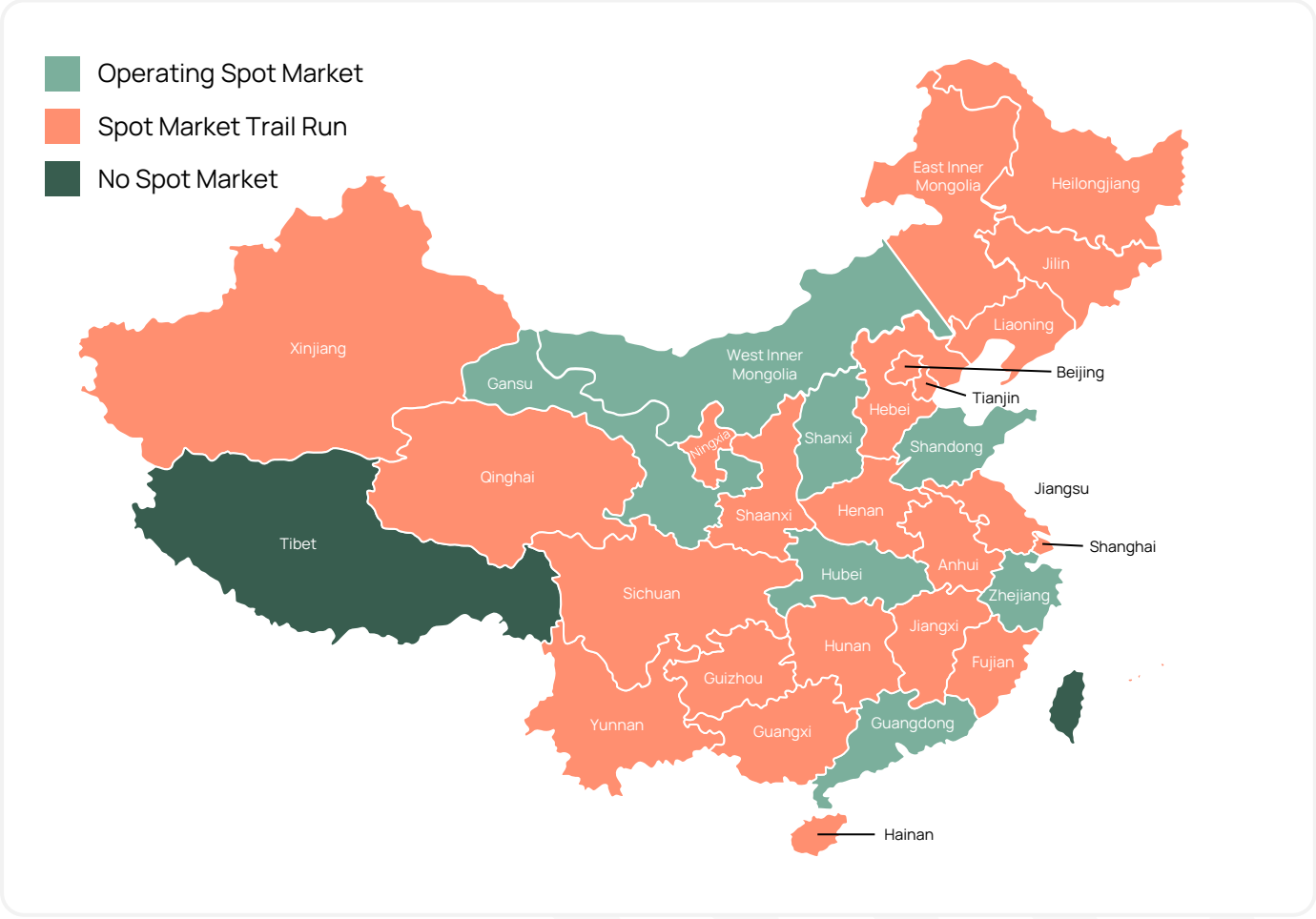
In contrast to the MLT market, which was rolled out in all provinces immediately following the execution of Document No. 9 in 2015, spot markets were implemented much more cautiously on a province-by-province basis. The spot market was designed as an eight-province pilot, with each province selected for its distinct characteristics, allowing China to explore optimal reform pathways through trial and error.

In 2018 the first pilot was set up in Shanxi Province, featuring real bidding, real dispatch, and financial settlement (albeit under trial rules). Over time, this trial was expanded from single-day runs to weekly, semi-monthly, monthly, and finally continuous trial operations. In December 2023, Shanxi's spot market was declared the first in the country to have entered official (formal) operation. As of Q1 2026, 7 provinces have now put their spot markets into formal operation, with many others conducting trial operations.

Spot markets in China comprise three main components. The day-ahead market organizes power trading in anticipation of power supply for the next day. The intra-day market allows for rolling adjustments to maintain supply throughout the day. Finally, the real-time market executes real-time load balancing for intervals as short as 15 minutes. The day-ahead market is universally present for all provinces with operating spot markets, while intra-day markets are currently still uneven and often limited. For instance, they are only activated in periods of system stress, or only operated by dispatch instructions, with no continuous trading available. Finally, the real-time (15-minute) markets are only used for dispatch and balancing by the system operator and are not widely settled or tradable at this time.

As they continue to mature, China's spot markets are increasingly able to create time granular price signals and settle deviations against those signals, revealing scarcity or flexibility value generally absent from MLT price formation. By revealing time dependent scarcity and flexibility through price formation, the spot markets provide an important analytical basis for considering whether green attributes could also be differentiated on a more granular basis.

Figure 18: Spot Market Development Status (End-2025)



Source: Provincial DRCs, provincial power exchanges

Ancillary Services Market

Products in China's ancillary services market include frequency balancing, black start and peak shaving.[39] The availability of the specific product types varies by province and regional grid. In 2024, expenditures in the national ancillary services market totalled CNY 40.25 billion (~USD 5.86 billion), with 82% attributed to peak shaving, 17% to frequency balancing, and the rest to reserves and other services. Because only market participants have access to the trading results and disclosing the settlement prices without authorisation is prohibited, provincial authorities generally only announce the range of allowable bid prices (see below).

Table 9: Allowable Bid Price Ranges for Ancillary Services in Selected Provinces

Province	Price	Note
Gansu	Battery: CNY 300 (~USD 44)/MW per day	2025 Nov and May prices
Sichuan	CNY 350 (~USD 51)/MWh	Battery's upper bidding price
Xinjiang	CNY 262 (~USD 38)/MWh	Upper bidding ceiling price
Hunan	CNY 450 (~USD 66)/MWh	Upper ceiling price
Shandong	CNY 400 (~USD 58)/MWh	Upper ceiling price for battery

Source: Provincial power exchanges

C.2.2. Price Formation in the Wholesale Power Markets

In the early stage of China's power market reforms, IPPs sold their generation to the local grid company at an on-grid rate approved by provincial policymakers on a case-by-case basis. A significant standardisation occurred in 2004 with the introduction of the provincial Coal-fired On-Grid Benchmark Price. This unified price benchmark for each province was calculated based on a comprehensive cost-plus model, factoring in steam coal costs, capital expenditures, standard operating hours, internalised environmental costs, and an allowable profit margin. It was updated periodically according to fluctuations in the price of coal, ensuring coal-fired generators could operate their plants with a reasonable rate of return. The last official update to the coal benchmark rate occurred in 2017, after which it began to be more commonly called the Coal Base Price.

39. NDRC & NEA, *Basic Rules for the Power Ancillary Services Market,* NDRC Energy Regulation [2025] No. 411.

Because the Coal Base Price was indicative of average procurement costs for coal-fired generation, and capacity in most provinces was dominated by coal, it was the natural choice for adoption as the price anchor for the nascent power markets. A permissible fluctuation range (initially +10%/-15%, later adjusted to ±20%) was established around it, and transactions in the MLT markets were required to adhere to this band. To the present day, although coal generators no longer receive fixed prices under today's market based dispatch regime, the legacy benchmark persists as the reference point for wholesale price formation.

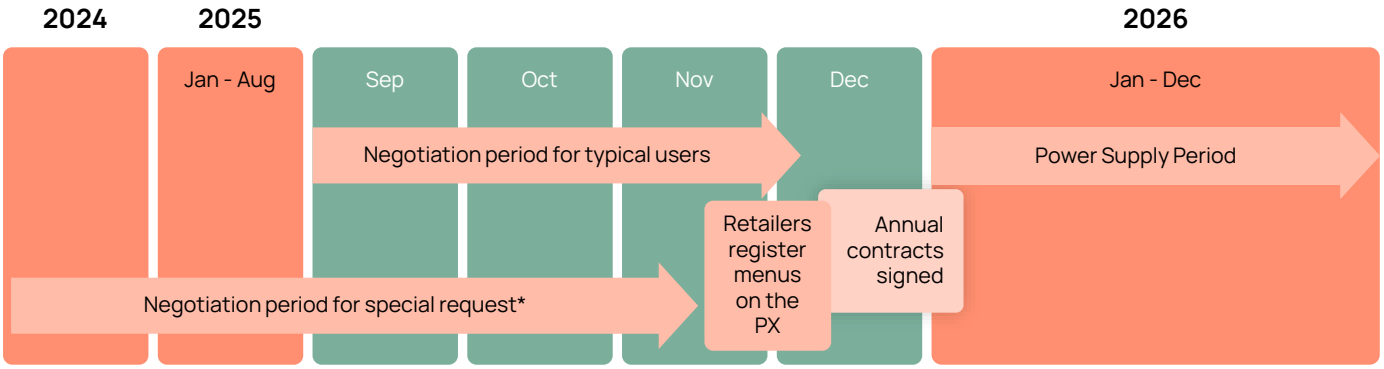
Although the MLT market features several different negotiation and transaction mechanisms, the market anchoring role of the provincial coal base price functions similarly for all of them. In bilateral MLT contracts, the energy price component (the "price of electrons") is freely negotiated between counterparties. On the other hand, for MLT volumes traded through exchange based listing and bidding mechanisms, prices are determined automatically via clearing on the power exchange-based on submitted bids and offers. Final wholesale prices deviate from the provincial coal benchmark according to generation costs, contractual positioning, and prevailing supply/demand conditions, but within the administratively defined price guardrails.

By contrast, in China's nascent spot power markets, prices are not negotiated bilaterally but formed through centralised clearing on the power exchange, typically via a day ahead market, followed by intra day and real time balancing settlement. Spot prices therefore reflect short run marginal system conditions, including updated load and renewable forecasts and network constraints, rather than negotiated contract outcomes. In contrast to the explicit ±20% coal benchmark collar governing MLT transactions, overt price caps or floors may not always be present in the spot market. However, prices may still be subject to administrative limits set by provincial authorities, and in some cases are still indirectly anchored to benchmark tariff levels.

C.2.3. The Retail Power Market

The retail power market is the key platform for C&I buyers and power retailers (both gen-tailers and independent retailers) to conduct power supply transactions. Like in the wholesale MLT market, bilateral negotiation accounts for the vast majority of transacted retail power volumes. Most eligible C&I users purchase power in the retail market via annual agreements negotiated and signed in Q4 of each year.

Figure 19: Typical Retail Power Agreement Timeline



** Users with large demand, or large green power demand in RE-scarce provinces*

Source: The Lantau Group

Multi-year (3-5 year) retail contracts are less common, but are available in some provinces, according to the rules of the local power exchange. Some power buyers may also enter multi-year agreements "outside" of the power exchange while registering their one-year supply agreement "inside" the exchange. However, one-year tenors remain the most common retail contracting term. Multi-month contracts are also available for buyers entering the market mid-year.

The retail markets in each province exhibit widely differing conditions and market arrangements, so each province must be treated as a unique procurement location for market participants. Factors that influence differing retail terms across provinces include local power supply and demand, whether the province is a net importer or exporter of power, the maturity of the local spot market, and the prevalence of certain types of loads or generators, among others. Terms and conditions that are standard and normal in some provinces may be unavailable in other provinces, while similar-looking terms may actually be executed very differently across different retail sectors. In addition, each province often updates its trading rules and policies annually, so the exact situation will evolve each year and must be carefully reviewed by market participants when the annual contract-signing season begins in December.

C.2.4. Price Formation in the Retail Power Market

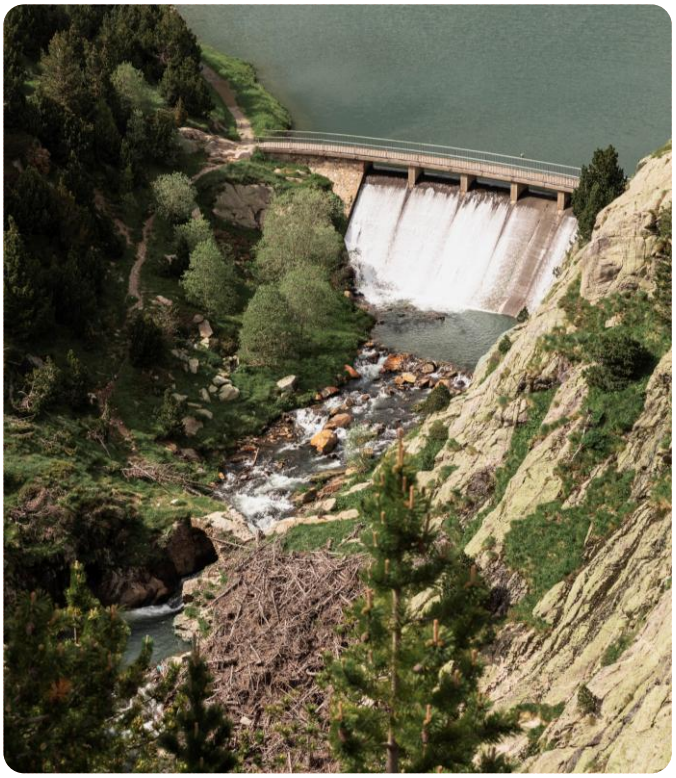
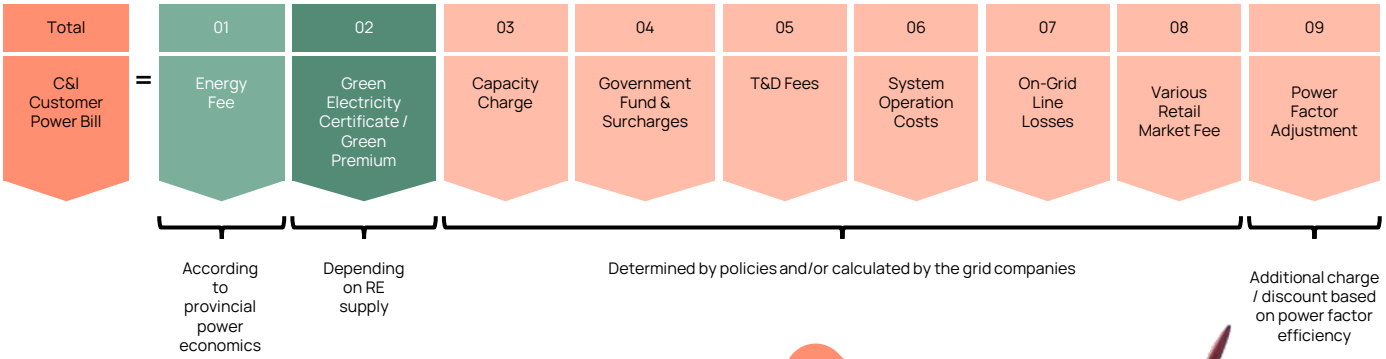


Figure 20: Typical C&I Power Bill Breakdown below shows the typical breakdown of a retail power user's power bill. In some provinces, retail buyers may also pay for an additional fixed rate or fixed charge (often called a "service fee") on top of the negotiated energy price, depending on the menu. The energy price, green premium, and fixed rate (if applicable) are the only cost items which are actually negotiable between power buyers and retailers, while the other items are determined by provincial or national policy.

Pricing options for the energy price often employ a combination of fixed and market-linked pricing mechanisms, which can be understood by buyers much like items on a restaurant menu. Market-linked retail products may allow a choice of or combination of different wholesale market rates as a pricing benchmark. Options typically at least include the monthly trading weighted average price and the spot market weighted average price.

Figure 20: Typical C&I Power Bill Breakdown



Source: The Lantau Group

ToU pricing is another important consideration. In retail menus without an explicit ToU scheme, the negotiated contract price typically applies as the default shoulder price, with provincially regulated ToU schedules imposing differentiated prices for peak and off peak periods. Several provinces (including Hubei, Henan, and Jiangsu in draft form) are now phasing out regulated ToU pricing for retail market customers, shifting temporal price formation toward market based supply/demand dynamics.

As this transition progresses, hourly menus that allow power buyers to contract different prices by hour and by month are expected to become a more common retail offering. This transition will also enable further time-differentiated approaches to clean energy accounting, including the use of granular green certificates to associate green claims with the same hourly structure used to price electricity.

Table 10: Common Options for Retail Menus

Menu Type	Energy Pricing Option
ToU Menu (in regulated ToU scheme, the hours and their multipliers are regulated, the 'shoulder' price is negotiable)	100% Fixed price (+ fixed "service fee").
	100% market-linked price (+ fixed "service fee")
	x% of fixed price + (1-x%) of market-linked price
	100% profit-sharing based on an agreed price: based on an agreed price, the parties share the difference between the wholesale electricity procurement cost and the agreed price at an agreed ratio
Hourly Menu (with 24 hr pricing)	100% Fixed price (+ fixed "service fee") for each hour Some provinces still set requirement on the price of non-shoulder hours (e.g. peak-hour price should be at least 160% of shoulder-hour price) in certain months
	100% spot-market-linked price (+ fixed "service fee") for each hour
	x% of fixed price + (1-x%) of profit-sharing based on an agreed price for each hour

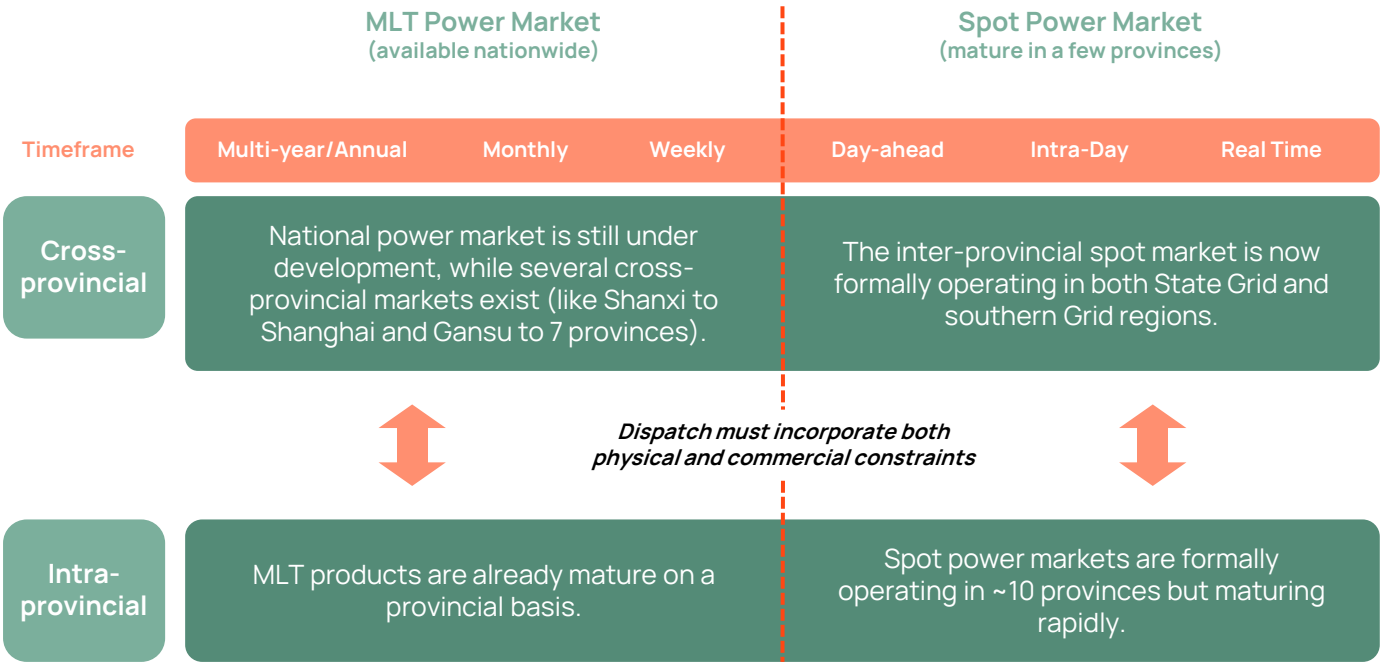
Green power retail menus are mostly constructed in the same way as thermal power retail menus. The key difference is that power buyers and retailers will also agree on a base power energy price as well as an explicit price/kWh for the green premium. The former is subject to any ToU schemes applicable while the latter remains flat and fixed for all hours. The value of the green premium is regulated to remain within a certain window in some provinces, while it is allowed to float freely in other provinces. However, the long-term trend is for more deregulated pricing. This separation between time varying energy prices and time invariant green premiums highlights a structural limitation of current retail designs but is also an attractive potential entry point for granular green certificates to represent the temporal attributes of renewable supply more explicitly. Granular certificates would thus extend ToU logic to the green premium itself, creating financial incentives for batteries that monthly matching cannot provide.

C.2.5. Power Supply for Non-Contestable Customers

Non-contestable power buyers like residential, agricultural, and small C&I power users are not obligated to buy power through power markets. Instead, they continue to enjoy power supply at regulated tariffs provided by the local grid company.

Additionally, the grid company serves as the delegated power supplier for any medium/large C&I power customers that have not yet entered the retail market. This is referred to as the grid-delegate scheme and has been a key transitionary mechanism for C&I power buyers. Local grid companies meet the power needs of their non-contestable and grid-delegate power buyers via a combination of long-term legacy PPA contracts (for example, with state-owned hydropower projects) and as-needed trading in the MLT wholesale markets.

Figure 21: Summary of Wholesale Market Structure in China

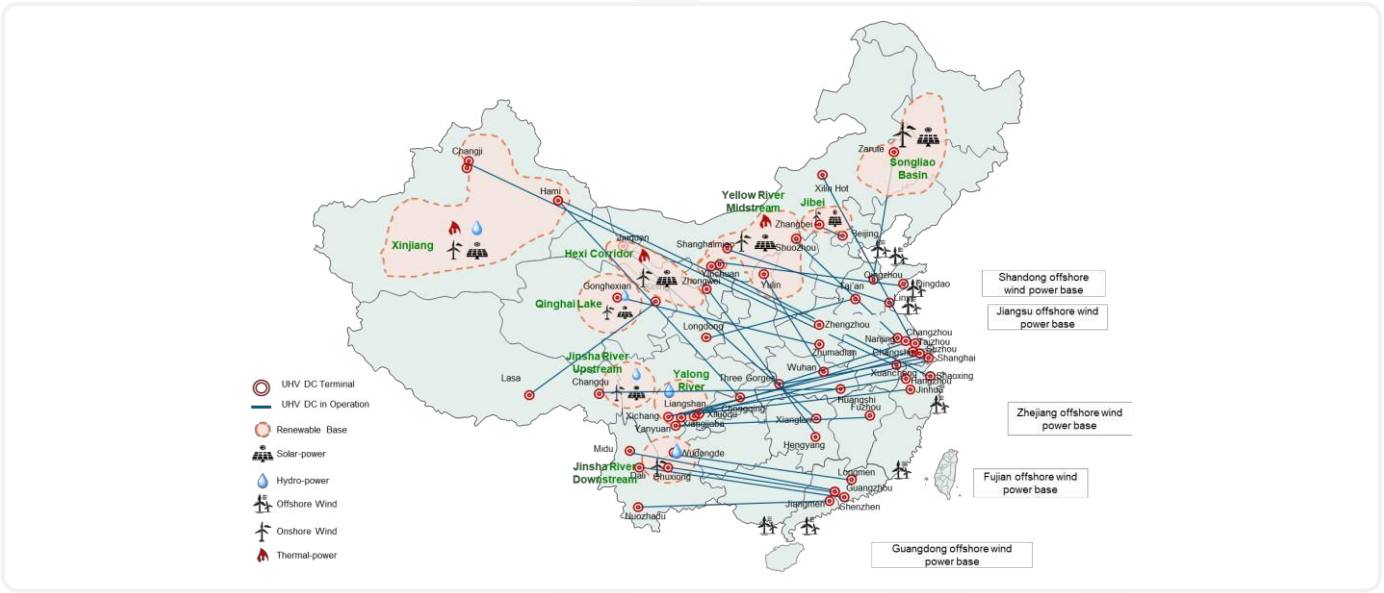


Source: The Lantau Group Analysis

C.2.6. Interprovincial Power Trading

While the province functions as the basic unit of the Chinese power system, few provinces are perfectly balanced at the provincial level, and most are either net importers or exporters of power. These cross-provincial trades are carried out in the inter-region power markets and fulfilled physically via long-distance high-voltage (HV) and ultra-high-voltage (UHV) transmission infrastructure. However, interprovincial trading can be constrained by both a lack of physical transmission lines between provinces as well as insufficient capacity on existing lines.

Figure 22: Operating UHV-DC Lines (August 2025)



Source: The Lantau Group

T&D infrastructure is primarily operated by one of China's two major grid companies: State Grid Corporation of China (SGCC), which operates the grids across northern, eastern, and central China, and China Southern Grid (CSG), which covers five provinces in the south.[40] While there are (limited) physical interconnections between the SGCC and CSG blocs, such cross-bloc trading is still infrequent as of the end of 2025.

Even when provinces are linked by transmission lines, trading depends on the availability of capacity on those lines for marketised dispatch. Most cross-regional transmission capacity is occupied by inter-governmental planned dispatch, often determined by long-term contracts signed years or even decades prior. After accounting for the planned dispatch and a reasonable safety margin, any remaining capacity will become available for use by marketised dispatch. As of 2026, there is no market for transmission rights trading in China, along with limited real-time information about line capacity. This is targeted for reform in the 2030-2035 timeframe.

From a market development perspective, interprovincial power trading in China today is operationally significant but institutionally immature. Most interprovincial power trading is conducted through scheduled, policy-driven, or event-based mechanisms, rather than continuously operating markets, and is dominated by medium- and long-term contracts. In mid-2025, the Southern Regional Power Market marked a major milestone in regional integration with continuous cross-provincial spot settlement on a trial basis, but this arrangement is still provisional and limited to the CSG region. Thus, even in the southern grid region, interprovincial trading is primarily a coordination layer on top of provincial markets, rather than a truly integrated market.

C.2.7. Operational Implementation of Interprovincial Trading

In practice, interprovincial trading is executed through a mix of ad hoc exchange-organised trading sessions and bespoke bilateral arrangements, with outcomes ultimately limited by physical transmission availability and system safety limitations. Regular green power trading sessions are also held within each grid company region. Participants transact via SGCC's e Trading app in the State Grid area or via Southern Grid Online in the CSG area, reflecting the continued separation between the two blocs. Beyond these routine sessions, additional volumes may be accessed through targeted arrangements tied to export-oriented resource bases (e.g., the renewable desert "superbases") or major hydropower export facilities (e.g., Three Gorges Dam). Provinces may also organise one-off import programmes to meet local corporate green power demand. Regional interprovincial MLT frameworks will expand as draft rules are finalised and approved.

Execution depends on coordination among power exchanges, grid companies, dispatch organisations, and (in some cases) provincial governments. For trades organised through Beijing Power Exchange or Guangzhou Power Exchange, this coordination is embedded in the exchange process, while for privately arranged deals, explicit coordination with the dispatch centres is necessary.

Because grid companies control access and scheduling across transmission corridors, multi province wheeling requires coordination among multiple provincial grid companies. Dispatch organisations conduct system-security checks and may adjust schedules after clearing or reduce cleared volumes for reliability reason. Therefore, the actual "greenness" of cross provincial dispatch is not always guaranteed. Cleared prices and settlements can shift when cleared volumes change. The operational impacts are borne by wholesale buyers and direct participants, but retail end users are typically insulated.

40. There is also the West Inner Mongolia Power Grid, which is operated by a separate company, but it is relatively minor and not discussed here.

Securing firm, guaranteed interprovincial delivery rights for MLT PPAs is not currently feasible. While these agreements can be signed contractually, physical delivery remains subject to transmission availability, real-time dispatch adjustments, and the absence of a transmission rights market. Currently, transmission rights may be secured by negotiating with a SOE which owns 100% of a cross-provincial transmission line. A generator located in the same grid as the SOE could negotiate and secure interprovincial delivery rights from that SOE. However, this is very rare as the lines are usually subsidised by the country and it is uncommon for SOEs to sell the transmission right freely. These constraints are expected to persist until relevant market reforms on transmission rights trading are implemented in the 2030–2035 period.

C.2.8. CPPAs in China

Historically, CPPAs have not been a mainstream procurement instrument in China's power sector, given the central role of the grid company (and, more recently, licensed retailers) as the primary counterparties for end users (the only exception to this arrangement had historically been the very limited number of wholesale power-buying end-users). As a result, corporate bilateral contracting has tended to be limited in scope and, where it occurs today, is most often associated with renewable procurement arrangements that have expanded alongside green power trading since 2021.

Where corporate PPAs are applied in practice, they are typically implemented as supplementary contracts to retail power contracts, rather than stand-alone delivery arrangements. The underlying retail contracts are based on standard templates published by the power exchanges, with executed versions registered as the basis for market participation and power dispatch. As a result, corporate buyers do not have the flexibility and creativity seen in the PPAs in more mature power markets. Instead, they must comply with the local power trading rules and most of the terms in the model contracts are fixed. Some of the key terms that parties may negotiate include:

- The contracted volume and load shape;
- The pricing mechanism (fixed or indexed to provincial benchmarks and/or market settlement);
- The allocation of deviation and imbalance charges between scheduled and metered quantities; and
- The treatment of curtailment and post-clearing operational adjustments.

CPPA feasibility in China remains highly province specific, reflecting differences in eligibil-ity, permitted tenors, retail market arrangements, and spot-market maturity.